2025 Resource Adequacy Assessment: Desert Southwest

Final Report

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Energy+Environmental Economics

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Acknowledgements & Disclaimer

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Tucson Electric Power Company (TEP)

Technical Advisory Group

Over the course of this study, E3 convened a Technical Advisory Group comprising individuals with expertise and interests in resource adequacy. These individuals graciously shared their time through several meetings, providing their feedback on the project's scope, technical analysis, and key findings. The Technical Advisory Group included the following individuals:

Genevieve de Mijolla, Electric Power Research Institute
Bethany Frew, National Renewable Energy Laboratory
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Branden Sudduth, Western Electricity Coordinating Council
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Gord Stephen, National Renewable Energy Laboratory
Gary Dirks, Arizona State University
Ryan Roy, Western Power Pool
Rebecca Sexton, Western Power Pool
Derek Stenclik, Telos Energy

E3 would like to thank the Technical Advisory Group for their valuable contributions over the course of the study. Participation in the Technical Advisory Group does not indicate endorsement of the report's findings.

Disclaimer

The study sponsors retained E3 to provide an independent assessment of the resource adequacy situation in the Desert Southwest region. The sponsors provided technical information and informed the development of study scenarios. E3 utilized data from the study sponsors and other sources to develop a Southwest resource adequacy model. E3 retained full editorial control over the report and is solely responsible for all contents.

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Acronym Definitions

Acronym	Definition
ACC	Arizona Corporation Commission
AEPCO	Arizona Electric Power Cooperative
APS	Arizona Public Service Company
BAA	Balancing Authority area
CAISO	California Independent System Operator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CRSP	Colorado River Storage Project
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
EPE	El Paso Electric Company
ESIG	Energy Systems Integration Group
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
HILF	High Impact Low Frequency
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NREL	National Renewable Energy Laboratory
NWPP	Northwest Power Pool
PNM	Public Service Company of New Mexico
RECAP	Renewable Energy Capacity Planning Model
SRP	Salt River Project
TEP	Tucson Electric Power
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WRAP	Western Resource Adequacy Program

1. Executive Summary

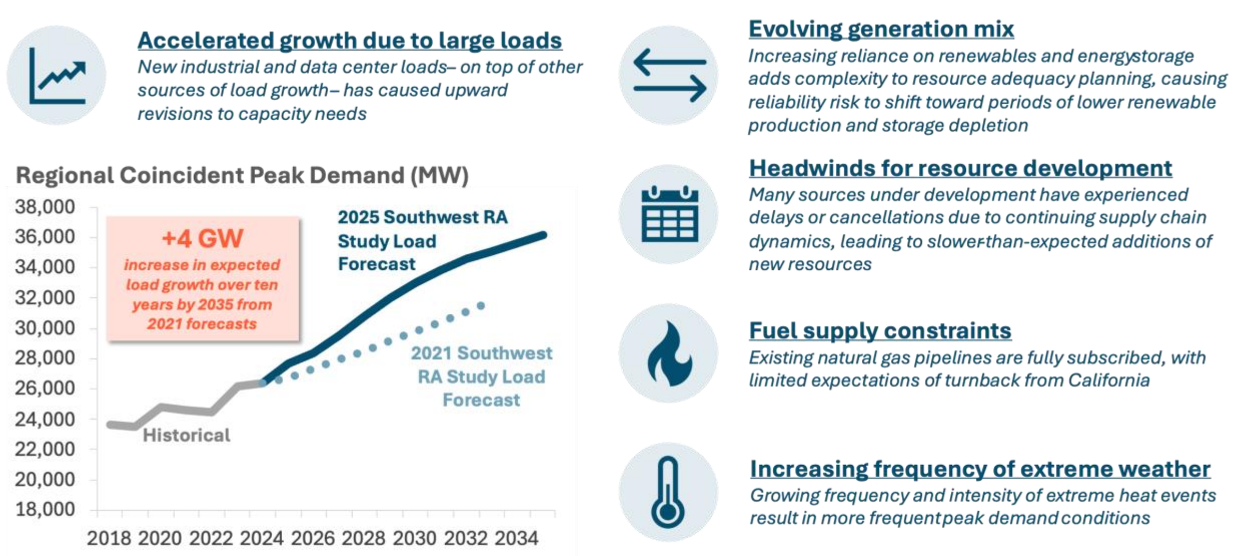
In 2022, E3 published ***Resource Adequacy in the Desert Southwest***, a comprehensive resource adequacy outlook for the U.S. Southwest region. Conducted shortly after high-profile reliability events in California (2020) and Texas (2021), the 2021 study quantified the resources needed to maintain regional reliability and evaluated whether utilities' plans would be sufficient to meet those needs using industry-leading loss-of-load-probability modeling. The study highlighted three key findings:

1. Load growth and aging plant retirements are creating a significant need for new capacity (13+ GW of effective capacity across the region by 2033) – but utilities' current resource plans have identified resources sufficient to meet those needs
2. A large share of the region's needs will be met with solar, storage, and other "non-firm" resources – but firm resources will remain essential for reliability
3. The scale of new resource additions needed requires unprecedented levels of development, necessitating immediate and sustained action over the next decade

These conclusions, as well as the study's thorough description of resource adequacy best practices, have since helped shape the regional discourse on resource adequacy.

Looking forward, the region's utilities face an increasingly complex set of challenges in planning a reliable electricity system. Transformational changes with direct implications upon the electricity system – some anticipated and some unforeseen – are underway, creating an environment of elevated complexity, uncertainty, and risk. These key developments are shown in Figure 1-1.

Figure 1-1. Key trends in the Southwest with direct implications for resource adequacy



Despite these developments, this assessment reaffirms the conclusions reached by the 2021 study, underscoring a pressing need for new resources and the importance of successful implementation of plans to ensure regional resource adequacy. In addition to reaffirming the prior study's near-term conclusions, this study extends the analysis to include a longer-term resource adequacy outlook beyond 2035.

1.1. Study Scope and Purpose

In light of these developments, the six utilities that sponsored *Resource Adequacy in the Desert Southwest* commissioned this follow-up study to provide an updated outlook of resource adequacy for the region. This study's scope is more expansive than the previous assessment, including both near-term and long-term evaluations of regional resource adequacy. The two assessments focus on different questions and rely on different modeling approaches:

- The **"Near-Term Assessment,"** which provides an updated projection of the region's resource adequacy position over the next decade based on utility plans, reprises the analytical methods used in the previous study using updated input data and considers the current progress and challenges towards implementing resource plans.
- The **"Long-Term Assessment"** extends beyond the scope of the prior study to evaluate the region's resource adequacy needs over a twenty-year period, exploring the features and characteristics of resource portfolios capable of meeting long-term resource adequacy needs. It does so by constructing and analyzing multiple hypothetical portfolios across a range of load forecasts and clean energy penetrations.[1] These portfolios are not projections or regional forecasts, but instead collectively show a range of potential long-term outcomes.

These two analyses complement to one another: the near-term analyses focus on the specific question of whether utilities' plans will be sufficient to maintain resource adequacy in the coming decade, while the long-term analysis explores a broader range of potential long-term portfolios, providing context for how near-term plans align with long-term needs. The scope and design of these two complementary efforts are contrasted in Table 1-1.

[1] The different clean energy penetrations are a key study design element and does not reflect the region nor any individual utility's goals. Changing the clean energy penetrations allows the study to explore common and uncommon patterns across a broader range of possible future portfolios and energy mixes.

Table 1-1. Contrasting scopes for the near-term and long-term assessments of resource adequacy

Study Element	Near-Term Assessment	Long-Term Assessment
Time Horizon	**Ten years** *(2025-2035)*	**Twenty years** *(through 2045)*
Modeling Tools	**RECAP** *(loss-of-load-probability)*	**PLEXOS & RECAP** *(long-term capacity expansion & loss-of-load-probability)*
Load Forecast	**Single load forecast** *provided as inputs by utilities and aggregated by E3*	**Three load forecasts** *developed by E3 to reflect a range of long-term growth outcomes*
Resource Portfolios	**Single portfolio** *provided as an **input** by utilities*	**Twenty-three portfolios** *created as **outputs** using LTCE*
Principal Study Question	***Are utilities' resource plans sufficient to meet near-term resource adequacy needs of the region?***	***What are the features and characteristics of resource portfolios capable of meeting long-term resource adequacy needs?***

Both phases of analysis in this study focus on evaluation of resource adequacy at a regional scale, and do not account for certain details or constraints that may impact the specific decisions made by each utility to meet its resource adequacy needs while balancing other planning objectives. Examples of utility-specific considerations that are not captured directly in this analysis include: (1) transmission deliverability, (2) constraints on fuel supply, (3) utility-specific portfolio considerations, and (4) regional resource adequacy programs (e.g. Western Resource Adequacy Program). As such, while the analysis provides useful indicative and directional results to present a picture of resource adequacy needs at a regional level, the analysis presented herein should not be viewed as a substitute for or alternative to each individual's planning processes.

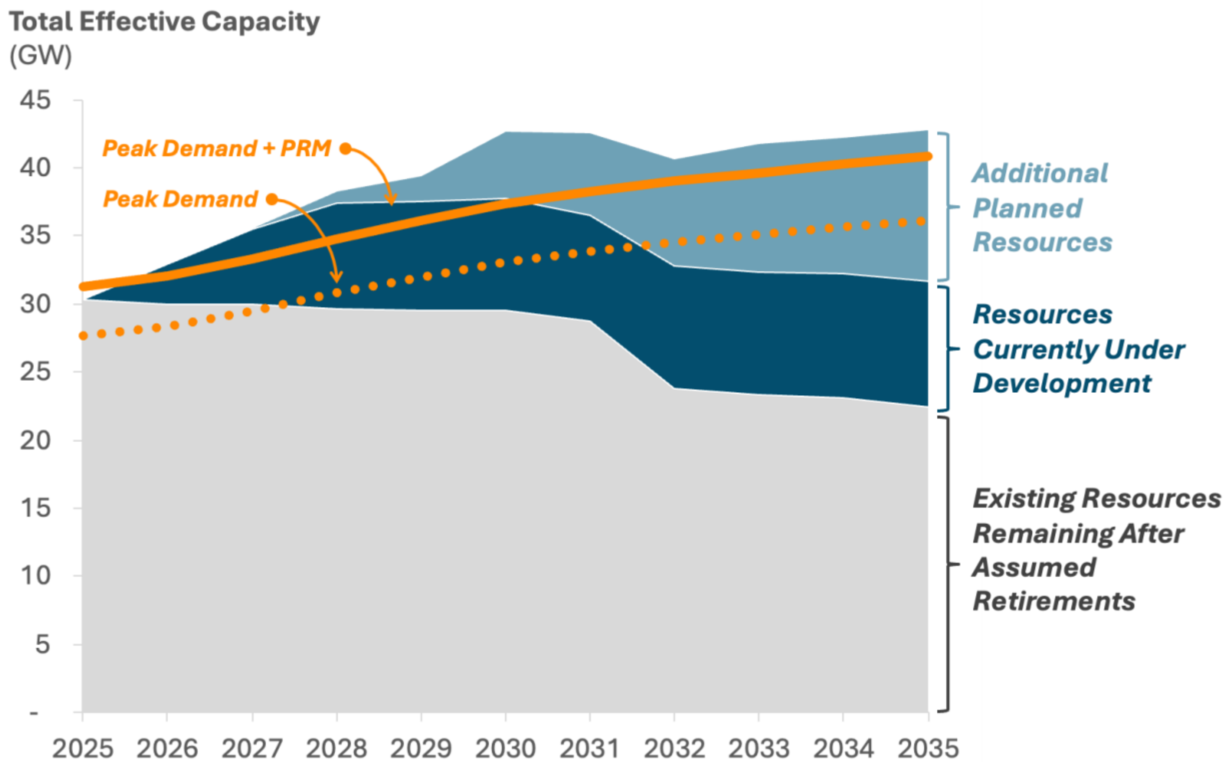
1.2. Near-Term Assessment Highlights

The near-term reliability outlook presented here uses load forecasts and resource portfolios provided by utilities in early 2025. Since that time, utilities have continued to update load forecasts and adjust resource plans in response to continuously changing conditions. For this reason, these results do not reflect the most current outlook for loads and resources within the region, but nonetheless serve as a useful directional indication of the relative scale of resource needs and provides validation that utility planning processes continue to identify resource portfolios capable of meeting regional reliability needs.

The near-term assessment provides a focused analysis on the adequacy of utilities' resource plans to maintain a level of reliability corresponding to a regional LOLE of 0.1 days per year or better. This analysis is conducted based on demand forecasts and portfolios provided directly by the utilities, which are analyzed using E3's RECAP model for LOLP modeling. Based on this analysis, Figure 1-2 shows the projected load-resource balance for the region under the assumptions used in this study, including both change in regional capacity need with growing loads and the effective capacity provided by existing resources, resources under development, and generic resources included in utility plans.

- Over the next decade, the aggregated demand forecasts identified across utility plans increase by 30%, or a total of over 8,000 MW. Incorporating a planning reserve margin of 13%, load growth increases the regional need for effective capacity by nearly 10,000 MW.
- At the same time, the retirements and expiring contracts of coal and natural gas plants assumed in this study result in the loss of approximately 8,000 MW of effective capacity.
- In conjunction, these two factors create a need for 18,000 MW of new effective capacity over the course of the next decade to maintain regional resource adequacy.
- Resources currently under development are poised to meet a portion of those needs, providing just over 9,000 MW of effective capacity and positioning the region to maintain load resource balance over the next several years.
- The additional generic resources included in utility plans are sufficient to close the remaining gap, creating some headroom in advance of planned resource retirements and satisfying the need for new capacity over the coming decade.

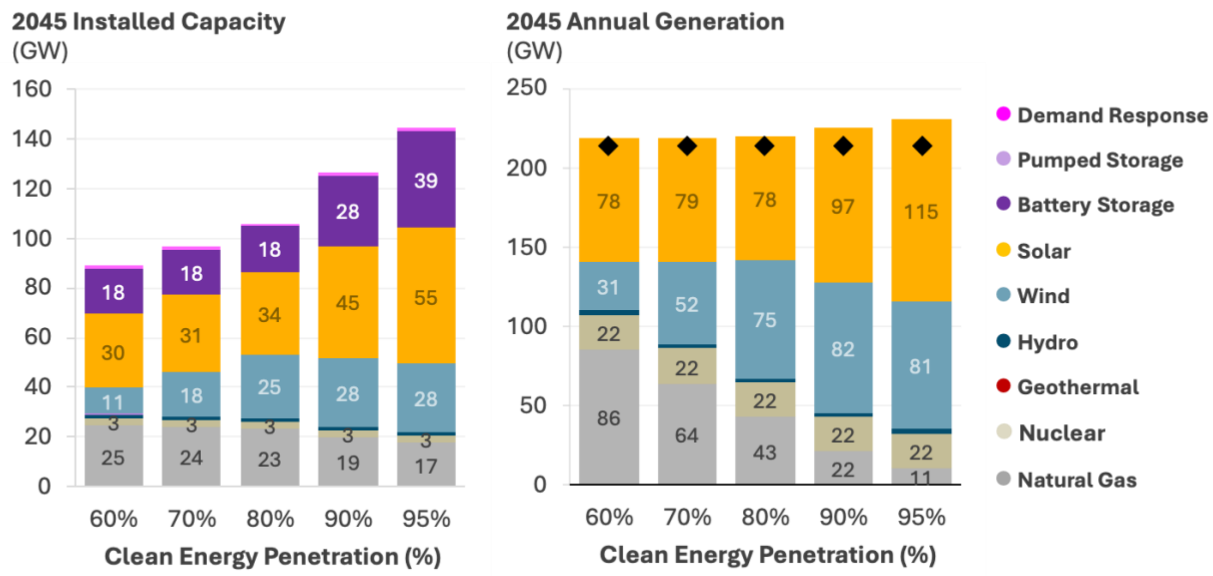
Figure 1-2. Projected regional load-resource balance according to utility plans current as of Q1 2025



1.3. Long-Term Assessment Highlights

The installed capacity and annual generation by resource type for five portfolios spanning clean energy penetrations from 60 to 95% under the Reference load forecast are shown in Figure 5-5. This collection of portfolios, each designed to meet a regional resource adequacy target of 0.1 days per year, show a range of plausible pathways to meet long-term energy and resource adequacy needs in the Southwest region.

Figure 1-3. Installed capacity and annual generation mix at different clean energy penetrations, Reference load forecast



Several observations are self-evident in these portfolios:

- While the specific quantities vary, all portfolios meet regional resource adequacy needs with a diverse mix of firm (gas and nuclear), renewable (wind and solar), and energy-limited (storage, DR, and hydro) resources.
- The differences in capacity among portfolios provides a measure of the relative effectiveness of firm, variable, and energy-limited resources in contributing to resource adequacy needs: from 60 to 95%, the total quantity of incremental renewables (+42 GW) and storage (+21 GW) is nearly eight times greater than the quantity of natural gas resources displaced (-8 GW).
- While the share of the energy mix served by natural gas decreases in inverse proportion to the penetration of clean energy resources, the amount of installed capacity needed to maintain reliability does not exhibit the same decline. Even in a 95% clean energy portfolio where natural gas accounts for only 5% of annual energy, the installed capacity of natural gas resources necessary to ensure reliability (17 GW) is roughly 40% of the system peak demand.

Additional sensitivities examine alternative load forecasts and the availability of emerging technologies, and while the composition of the portfolios adjust according to the specific assumptions made, the general observations described above hold true across all scenarios modeled.

1.4. Key Findings

The near-term and long-term assessments inform six key findings from this assessment. The first three focus primarily upon the results of the near-term assessment, and the second three build upon these based on the results of the long-term assessment.

1. Need for New Resources is Urgent

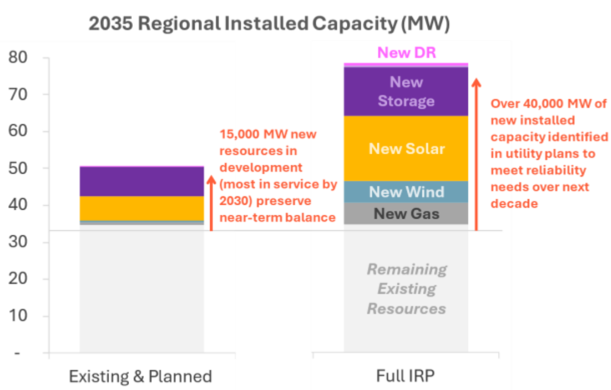
Large increases in regional demand, coupled with anticipated retirements, continue to drive a significant need for new resources across the region to maintain reliability

Over the next decade, the anticipated demand based on utility inputs to this study shows regional coincident peak demand increasing from roughly 27,500 MW to over 36,000 MW. At the same time, assumed retirements and expiring contracts with existing resources result in the loss of nearly 8,000 MW of effective capacity from the 2025 existing portfolio. For a system at or near load-resource balance today, the compound effect of these two changes is a total need for new *effective* capacity of roughly 18,000 MW over the next decade.

2. Utility Plans Demonstrate Adequacy

Over the next decade, utilities' resource plans include new natural gas, renewables, and storage sufficient to maintain regional resource adequacy

Collectively, the utilities' resource plans provided as inputs for this assessment include over 40,000 MW of new installed capacity by 2035. If these resources are successfully brought in service according to prescribed schedules – which will require a rate of new resource additions far greater than recent historical trends – this study shows that the region will maintain sufficient generating capacity to ensure a level of resource adequacy consistent of LOLE of 0.1 days per year or better.



Notably, the *nameplate* capacity of the resource additions included in utility plans (40,000 MW) far exceeds the amount of *effective* capacity they provide to the system to ensure reliability due to the inherent limitations of variable and energy-limited resources.[2]

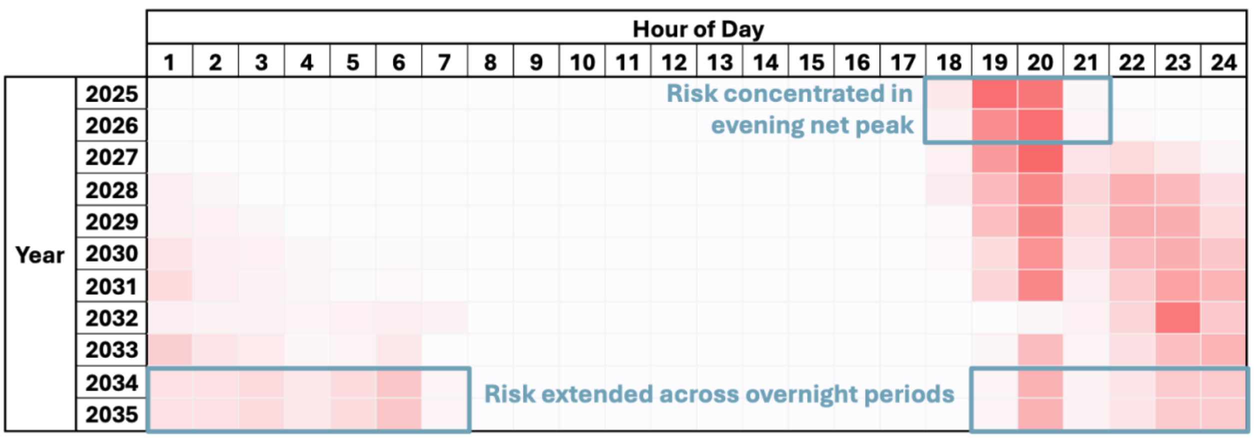
[2] Effective capacity (or perfect capacity) measures a resource's contribution to resource adequacy, typically measured against a "perfect resource" or a resource that is available at all times.

3. Reliability Risks are Shifting Rapidly

Reliability risk has already shifted from afternoon peak to the evening "net peak," and will extend deeper into overnight periods as resource mix evolves

The Southwest utilities are planning to meet a growing share of future resource adequacy needs with renewable and energy storage resources; by 2035, these resources are projected to account for roughly half of the total effective capacity in the region. These portfolio changes directly impact the timing of reliability risks, which shift away from the traditional peak period as penetrations of variable resources rise. This effect is already present in today's system, as the growth of solar has caused risk to shift into the evening. Over the next decade, increasing levels of energy-limited resources will continue to shift and extend the periods when the system is at the edge of reliability (see Figure 1-4). Based on utility plans, higher risks in the late evening and overnight periods could begin to emerge as soon as 2027.

Figure 1-4. Relative loss-of-load risk by time of day based on utility plans, 2025-2035



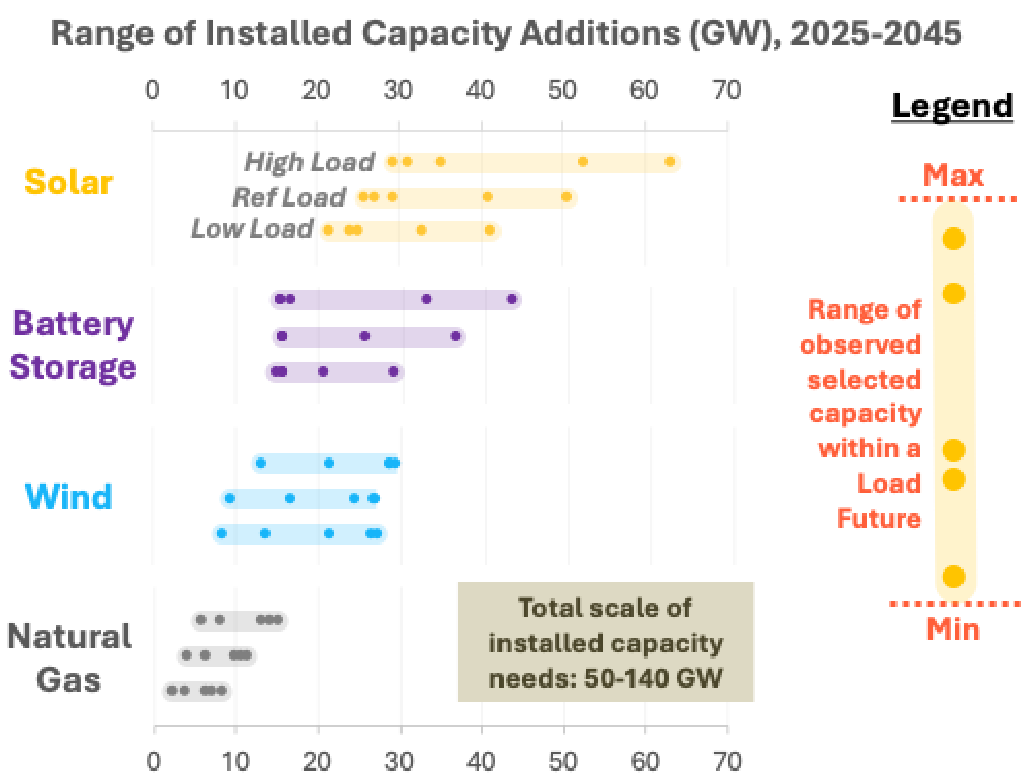
These effects are caused by evolving portfolio identified across all utilities to meet their needs, and in turn, directly impact the contributions that additional resources can make to resource adequacy in multiple ways. With existing solar penetration shifting risk to late evenings, marginal solar additions provided limited reliability value (marginal solar provides between 5 to 7%). Beyond 2027, the extension of risk into the overnight periods contributes to the observed declines in the marginal capacity value of short-duration storage resources (4-hr storage decreases from 90% in 2025 to 38% in 2035), which in turn increases the relative value of resources that can provide longer duration services to the grid and firm resources capable of generating over sustained periods without limits on their use.

4. Diversity is a Robust Long-Term Strategy

Meeting growth with a combination of new gas, renewables, and storage resources is a robust strategy across a wide range of longer-term future conditions

Beyond 2035, maintaining resource adequacy, as loads continue to grow and existing resources retire, will require substantial investments in new resources. This study demonstrates that regional resource adequacy can be met with a wide range of resource mixes, showing reliable resource portfolios that span from 60 to 95% clean energy; across all portfolios studied, the total amount of new installed capacity added between 2025 and 2045 ranges from 50 to 140 GW. In all cases where the availability of commercially available technologies is not explicitly restricted, long-term needs are met by a diverse mix of new renewables, storage and natural gas resources; the range of new resource additions by technology across the twenty-year period are shown in Figure 1-5. To the extent emerging technologies mature, they may also contribute to regional resource adequacy needs (as evidenced by the selection of new nuclear in several portfolios) but do not appear to diminish the importance of resource diversity. All portfolios also include continued expansion of energy efficiency and demand response; beyond these levels, additional demand-side resources (including behind-the-meter generation, virtual power plants, and incremental energy efficiency and demand response) could also contribute to meeting regional needs if they provide capabilities aligned with the future needs of the electricity system.

Figure 1-5. New installed capacity additions from 2025 to 2045 across portfolios in the long-term assessment

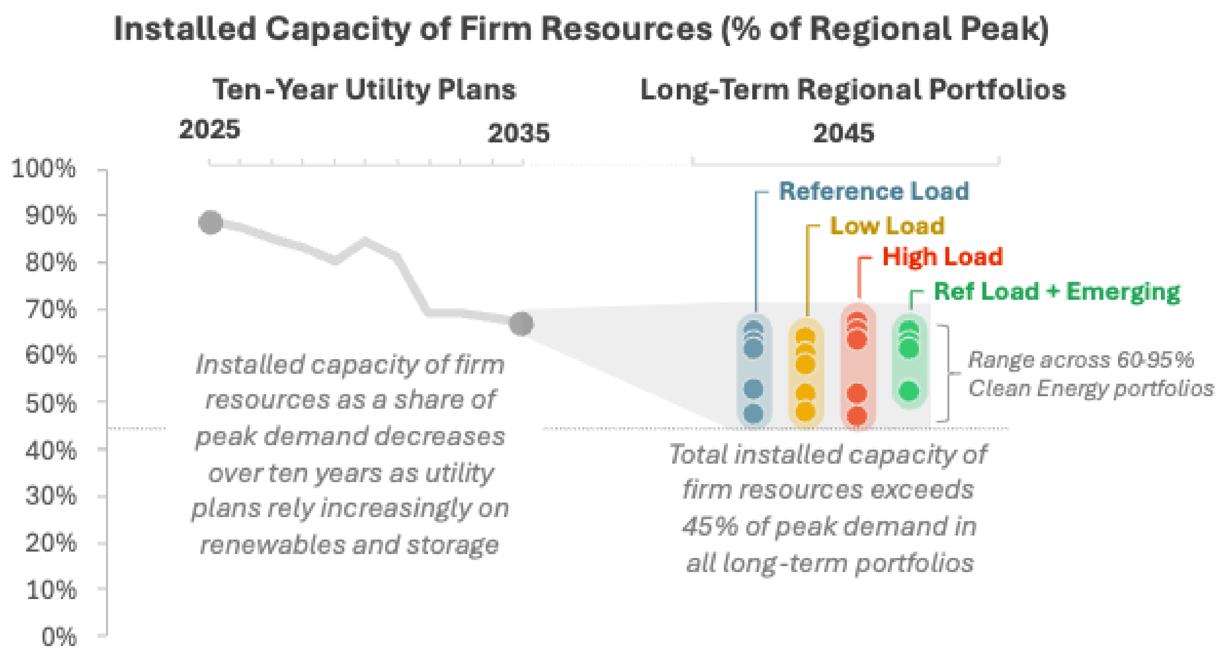


5. Firm Resources are Critical to Reliability

Firm generation resources remain essential to ensuring long-term resource adequacy and mitigating risks of large energy deficiencies, particularly during periods when renewable output is low

While the contributions of variable and energy-limited resources to resource adequacy are substantial across all portfolios analyzed, both categories of resources are subject to significant declines in their marginal capacity value at higher penetration. In practice, this means that even if portfolios include renewables and storage capable of serving most annual energy needs, ensuring resource adequacy also requires "firm" resources capable of producing energy across sustained periods when renewables and energy storage may be unavailable. Across all portfolios analyzed in the long-term assessment where new firm resource options are unconstrained, their total installed capacity ranges between 45-70% of system peak demand (Figure 1-6). In all long-term portfolios, nuclear and natural gas resources play a critical role in ensuring reliability when electric demand is high, renewable availability is low, and energy storage resources have been depleted (for instance, during cloudy winter weeks). Under such conditions, resources with the capability to generate on demand for as long as necessary allow the system to maintain reliability.

Figure 1-6. Summary of firm resource contributions across near-term and long-term assessments

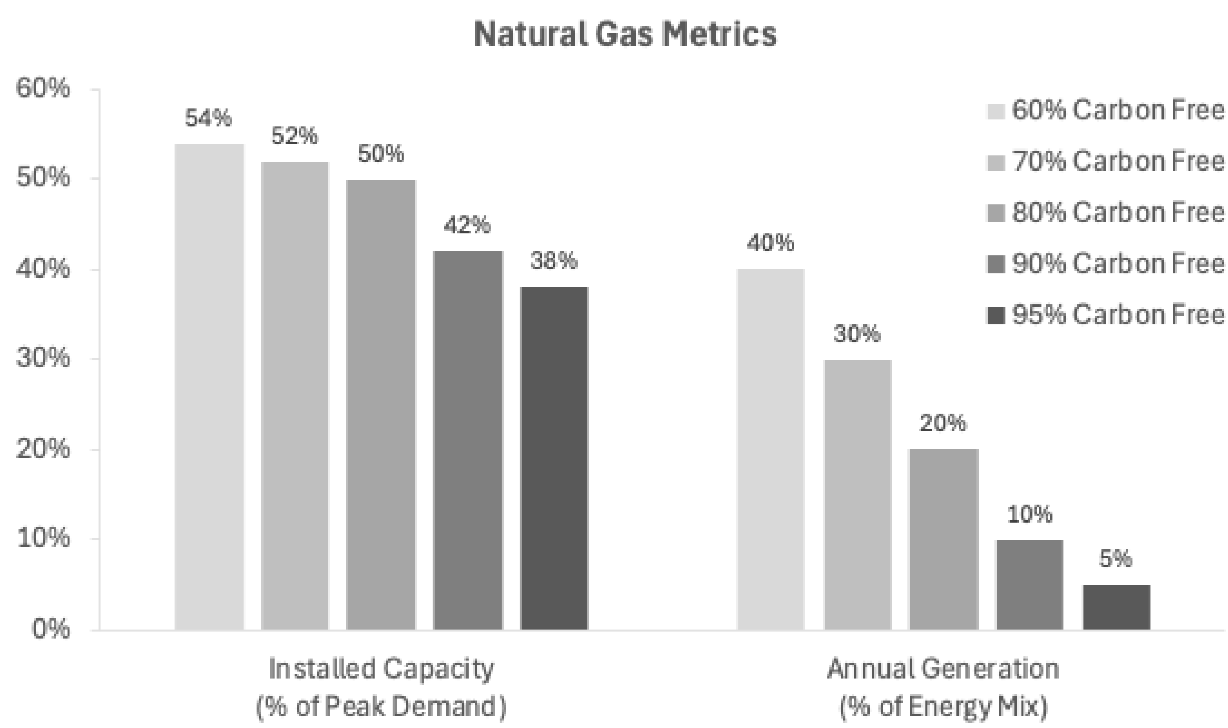


6. Natural Gas Remains the Primary Firm Option

Across all portfolios, natural gas fulfills the majority of the region's long-term need for firm resources, even under the highest clean energy penetrations studied.

The range of portfolios in the long-term assessment yields useful insights into the future adequacy of natural gas, captured through three metrics, shown in Figure 1-7: (1) **installed capacity,** the total gas capacity needed to ensure reliability and (2) **annual generation,** the share of regional energy produced by gas-fired resources. Across the portfolios, as clean energy penetration rises from 60 to 95%, annual gas generation falls sharply (from 40% to 5% of total energy) while installed capacity declines only modestly, from 54 to 38% of peak demand. This contrast is the key finding: increasing clean energy primarily reduces how often gas resources must run, not how much capacity is required. Even at 95% clean energy, a large amount of natural gas capacity (nearly 40% of peak demand) plays a critical reliability role, where it serves as a rarely-used backstop option during periods of low renewable output.

Figure 1-7. Key metrics for natural gas fleet in long-term adequacy assessment



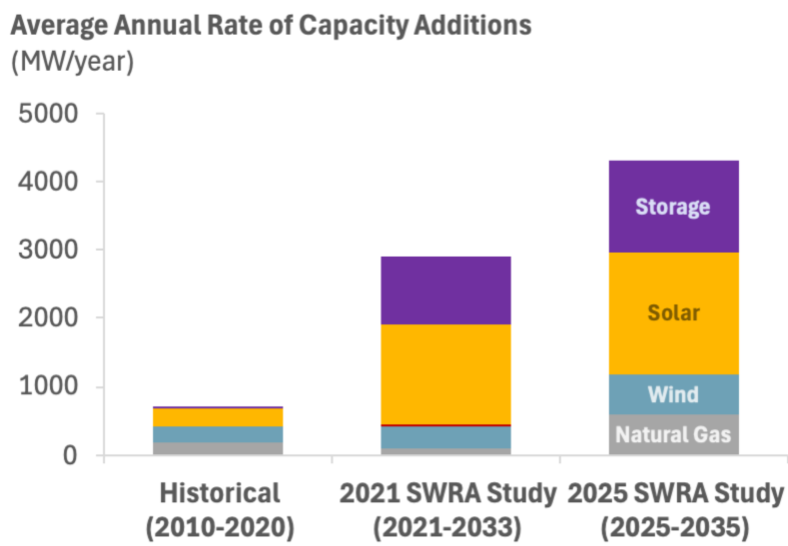
These results further underscore the finding that additions of new natural gas resources to the region are part of a robust strategy to meet near- and long-term resource adequacy needs, capable of supporting grid reliability across a wide range of future clean energy penetrations and load levels.

1.5. Study Implications

Both the 2021 and 2025 assessments indicate that, despite increasing portfolio complexity and evolving resource adequacy risks, the utilities' collective planning practices are effective in their identification of resource portfolios with the technical ability to maintain regional resource adequacy. Notably, the two assessments reached this conclusion while evaluating different load forecasts and resource portfolios. The consistency of this technical result provides strong evidence that utilities' methods and analytical toolkits provide a sound foundation for resource adequacy planning, and that utilities have used this foundation to adjust plans quickly in response to the changing outlook for future demand.

Having demonstrated that the utilities' plans have the technical capability to meet projected needs, the most immediate challenge for maintaining regional resource adequacy lies in successful implementation. Meeting the needs forecasted in this study would require that utilities add over 4,000 MW of new installed capacity to the system each year over the next decade – a quantity that exceeds the necessary rate of additions previously identified in the 2021 study and eclipses the long-term historical average by a factor of four (see Figure 6-5).

Figure 1-8. Comparison of annual average capacity additions



In an environment marked by heightened uncertainty and rapid change, translating these plans into reliable real-world outcomes presents a more multifaceted set of challenges than the planning itself. Successful implementation will require coordinated orchestration across a range of processes, systems, and institutions involving a wide range of regional stakeholders. The region's utilities will naturally play a central role in each step of implementation, but the ultimate outcomes will reflect the collective performance of actors and systems that no single entity controls. Given the rapid pace of change and potential for unanticipated shifts in the energy landscape, even well-formulated plans will likely require frequent reevaluation and revision; the ability to monitor emerging conditions, identify gaps early, and adapt accordingly will be as important as the plans themselves. The risk factors in Table 1-2 represent the most significant aspects of implementation required to ensure resource adequacy.

Delays or unexpected obstacles caused by any one of these factors – or further increases in regional demand not anticipated at the time of this study – could jeopardize utilities' ability to add resources to the system at the pace needed to meet regional growth projections reliably. To mitigate these risks and support successful implementation, utilities and regional stakeholders can focus on several near-term actions.

While these actions cannot fully eliminate implementation risk, sustained focus in these areas will improve the likelihood that planned resources are delivered on time and that regional reliability is maintained under increasingly uncertain conditions.

Table 1-2. Summary of implementation considerations and potential strategies to limit risk

Implementation Consideration	Description of Potential Risks	Potential Solutions
Load Forecast Uncertainty	Large customer growth continues to be highly uncertainty, making reliability planning a moving target	• Strengthen interconnection and service agreements • Design rates or tariffs that better align large customer development with system planning needs
Procurement Risk & Supply Chain	Supply chain constraints have led to increasing project costs, longer lead times for equipment, and project delays and cancellations	• Initiate procurements earlier in advance of resource need • Maintain diversified pipeline of projects • Incorporate flexibility to account for delays or cancellations • Leverage cost-effective demand-side programs to limit bulk system needs
Transmission Interconnection & Deliverability	Large scale of resource development will also require coordinated buildout of transmission system, which can include longer study processes and long lead times	• Pursue parallel development of generation and transmission through Integrated System Planning • Prioritize transmission upgrades that unlock multiple resources • Repurpose existing infrastructure made available as legacy plants retire
Permitting & Regulatory Approval Processes	New projects require permits and regulatory approvals from a variety of bodies (e.g. local governments, regulatory agencies and boards, and federal bodies) – each of which poses potential to delay development	• Engage early with permitting agencies and local communities • Explore potential to streamline local permitting with model ordinances • Repurpose brownfield power plant sites
Operations & Market Integration	Increasingly penetrations of variable and energy-limited resources add complexity to grid operations, requiring accurate forecasting and sophisticated dispatch algorithms to maximize storage value	• Invest in advanced forecasting, grid visibility tools, and optimized dispatch strategies • Coordinate with market operators to ensure market rules enable maximum storage value
Fuel Supply	Plans to right-size fuel transportation rights for a growing gas fleet depend in part on development of a new interstate pipeline, a large multijurisdictional infrastructure project that could experience delays for a variety of reasons	• Secure fuel transportation capacity • Identify short-term risk mitigation strategies to ensure adequacy in the event of delay

2. Introduction

In 2022, E3 published ***Resource Adequacy in the Desert Southwest***, a thorough analysis of the resource adequacy outlook for the region over the coming decade. Following shortly after high profile reliability events in California (2020) and Texas (2021), this study sought to quantify the resource needs to ensure reliability and evaluate the adequacy of utilities' plans to meet those needs using industry-leading loss-of-load-probability modeling. Three key findings emerged from the analysis:

1. Load growth and aging plant retirements are creating a significant need for new capacity (13+ GW of effective capacity across the region by 2033) – but utilities' current resource plans have identified resources sufficient to meet those needs
2. A large share of the region's needs will be met with solar, storage, and other "non-firm" resources – but firm resources will remain essential for reliability
3. The scale of new resource additions needed requires unprecedented levels of development, necessitating immediate and sustained action over the next decade

These key findings, as well as the study's thorough description of resource adequacy best practices, have since helped shape the regional discourse on resource adequacy.

2.1. Key Developments Since 2021

Since 2021, observed resource additions in the Southwest have largely aligned with projections from five years ago. While load growth has slightly outpaced prior forecasts, the region has largely maintained a stable balance of loads and resources during this period.

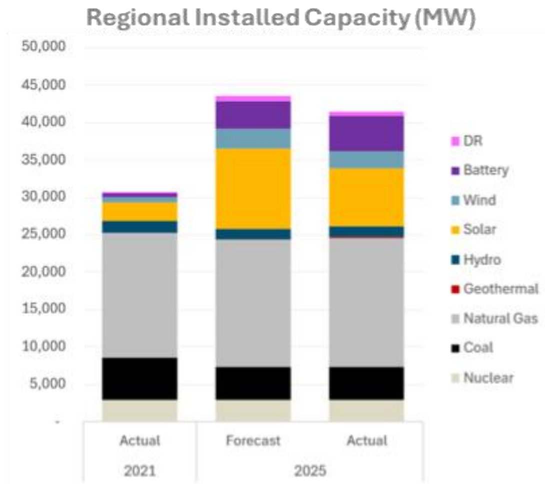
- Regional electricity demand has grown at a slightly faster rate than anticipated, exceeding previous forecasts by roughly 750 MW.
- The capacity of firm resources (nuclear, coal, and gas) has closely aligned with projections, showing a slight reduction since 2021 with retirements at Cholla and San Juan power plants.
- Additions of solar and wind resources have lagged projections by roughly 3,000 MW and 500 MW, respectively; a reflection of development challenges experienced by many of the projects under development in the region;
- Additions of energy storage resources have exceeded previous projections by roughly 1,000 MW, helping preserve load-resource balance despite other headwinds and stressors.

A summary comparison between the 2025 projections from the 2021 study and actual current conditions is provided in Figure 2-1.

Figure 2-1. 2025 system comparison: projections from 2021 study vs. actual

Comparing the Outlook for 2025 vs. Actual Results

Impact on Resource Adequacy : Actual vs. Forecast		
Load Growth	●	Load growth slightly higher than forecast: Actual CP (**27,500 MW**) vs. forecast CP (**26,750 MW**)
Coal Retirements	-	Cholla & San Juan retired as planned
Natural Gas Additions	-	Small capacity upgrades, no major new generation projects added through 2025
Renewable Additions	●	Fewer new solar resources added than plans
Storage Additions	●	More new energy storage resources developed
Overall Regional Position	●	**Regional resource adequacy position slightly tighter than anticipated**



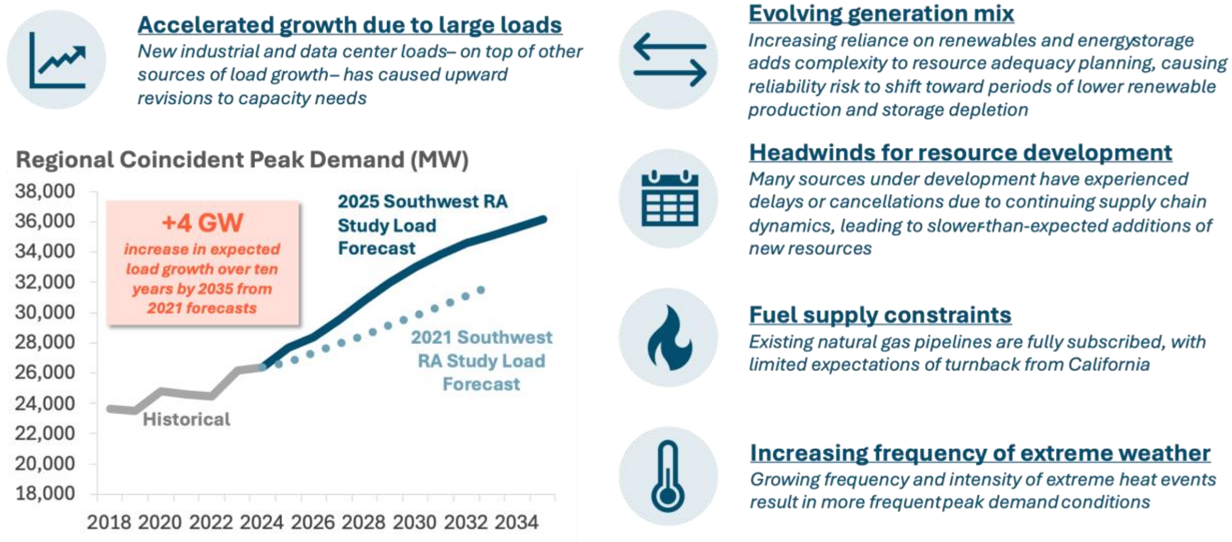
Looking forward, the region's utilities will continue to face an increasingly complex set of challenges in planning a reliable electricity system. Transformational changes with direct implications upon the electricity system – some anticipated and some unforeseen – are underway, creating an environment of elevated complexity, uncertainty, and risk. These include:

- **Accelerating load growth,** due primarily to an increase in the number of data centers and other large manufacturing and industrial customers seeking electric service in the Southwest;
- **Evolving resource mix** and the corresponding task of planning and operating an increasingly complex electricity system that includes a mix of firm, variable, and energy-limited resources.
- **Resource development headwinds,** including delays and cancellations of projects under development, as constraints in global and domestic supply chains have driven unanticipated cost increases and equipment backlogs;[3]
- **Fuel supply constraints,** as the existing interstate pipeline system that delivers natural gas to generation resources within the region is nearly fully subscribed;
- **Increasing frequency of extreme weather,** including record-breaking heat waves in key population centers[4];

These evolving trends and the challenges they pose to utilities are summarized in Figure .

[3] Between 2021 and 2025, increased demand for all resources, but supply chains
[4] See, for example: https://www.nytimes.com/2023/07/31/us/phoenix-heat-july.html

Figure 2-2. Key trends in the Southwest with direct implications for resource adequacy



2.2. Study Scope and Purpose

In light of these developments, the six utilities that originally sponsored *Resource Adequacy in the Desert Southwest* have commissioned this study to provide an updated forward-looking view of resource adequacy across the region. This study's scope is more expansive than the previous assessment, including both near-term and long-term evaluations of regional resource adequacy needs. The two assessments focus on different questions and rely on different modeling approaches to answer them:

- The **"Near-Term Assessment,"** which focuses on the region's position over the next decade based on utility plans, reprises the modeling tools and approach used in the previous study to provide an updated outlook on resource adequacy.
- The **"Long-Term Assessment"** extends beyond the scope of the prior study to evaluate the region's resource adequacy needs over a twenty-year period, exploring the features and characteristics of resource portfolios capable of meeting long-term resource adequacy needs. It does so by constructing and analyzing multiple hypothetical portfolios across a range of load forecasts and clean energy penetrations.[5] These portfolios are not projections or regional forecasts, but instead collectively show a range of potential long-term outcomes.

These two analyses complement one another: the near-term analyses focus on the specific question of whether utilities' current plans will be sufficient to maintain resource adequacy in the coming decade, while the long-term analysis widens the aperture to explore a broader range of potential

[5] The exploration of clean energy penetration across different portfolios is a specification enforced for this study's design. With this specification for each portfolio, the study can explore a range of portfolios with different resource mixes, varying in levels of gas, storage, and renewables to meet resource adequacy in the Southwest.

long-term options that provide context for how decisions made in the near-term will impact the region across the next several decades.

The scope and design of these two complementary efforts are contrasted in Table 2-1.

Table 2-1. Contrasting scopes for the near-term and long-term assessments of resource adequacy

Study Element	Near-Term Assessment	Long-Term Assessment
Time Horizon	**Ten years** *(2025-2035)*	**Twenty years** *(through 2045)*
Modeling Tools	**RECAP** *(loss of load probability)*	**PLEXOS & RECAP** *(long-term capacity expansion & LOLP)*
Load Forecast	**Single load forecast** *provided as inputs by utilities and aggregated by E3*	**Three load forecasts** *developed by E3 to reflect a range of long-term growth outcomes*
Resource Portfolios	**Single portfolio** *provided as an **input** by utilities*	**Twenty-three portfolios** *created as **outputs** using LTCE*
Principal Study Question	***Are utilities' resource plans sufficient to meet near-term resource adequacy needs of the region?***	***What are the features and characteristics of resource portfolios capable of meeting long-term resource adequacy needs?***

Both phases of analysis in this study focus on evaluation of resource adequacy at a regional scale, and do not account for specific details or constraints that may impact the decisions made by each individual utility to meet its resource adequacy needs while balancing other planning objectives. Examples of utility-specific considerations that are not captured directly in this analysis include: (1) transmission deliverability, (2) constraints on fuel supply, and (3) utility-specific portfolio considerations. As such, while the analysis provides useful indicative and directional results that present a picture of resource adequacy needs at a regional level, the analysis presented herein should not be viewed as a substitute for or alternative to each individual utility's planning processes.

2.3. Report Contents

The remainder of this report is organized as follows:

- **Section 3** provides general background on resource adequacy and discusses key trends impacting resource adequacy planning for Southwest utilities;
- **Section 4** presents the near-term resource adequacy assessment;
- **Section 5** presents the long-term resource adequacy assessment; and
- **Section 6** provides key findings of the two assessments and discusses their implications.

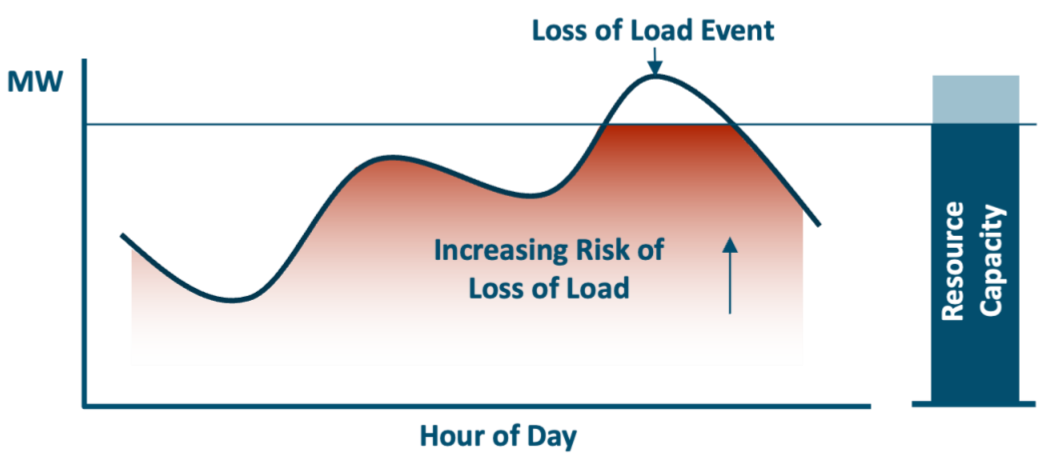
3. Study Background

3.1. Defining Resource Adequacy

Resource adequacy is the ability of an electric power system to produce sufficient generation to meet loads across a broad range of weather and system operating conditions, subject to a long-run reliability target that limits the frequency of shortfalls to very rare instances. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability. Ensuring resource adequacy is an important goal for utilities seeking to provide reliable service to their customers.

> **NERC Definition of Resource Adequacy**
>
> *"The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."*

Figure 3-1. Illustration of a loss of load event due to insufficient generation



While there is no single mandatory standard defined for resource adequacy, many utilities – including all sponsors of this study – rely on some interpretation of the "one day in ten years" planning target. While this rule of thumb has been interpreted in a number of different ways, the most common interpretation relies allows for a Loss of Load Expectation (LOLE) of 0.1 days per year. While there is no formal resource adequacy standard currently established for the Southwest region as a whole, the near-ubiquity of the one-day-in-ten-year target makes it useful as a benchmark for this study, and regional resource adequacy is evaluated relative to an LOLE of 0.1 days per year.

3.2. Recent Industry Trends and Developments

3.2.1. Increasing Load Growth

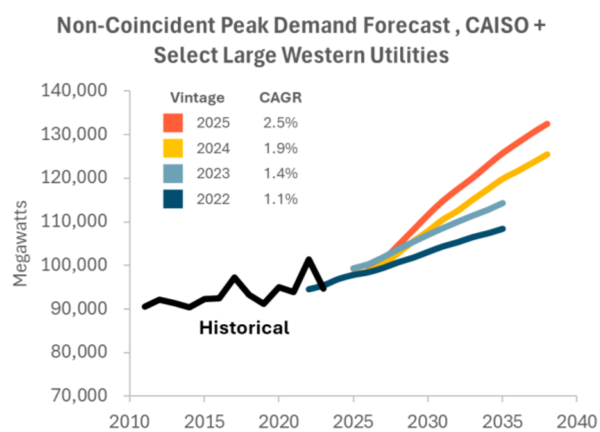
Arguably the most significant development since the 2021 study has been the increase in demand forecasts among utilities in the Southwest. These increases are largely the result of updates to the outlook for data centers and other large technological and industrial customers. The forecasts provided as inputs to this study, in aggregate, reflect a 20% increase in 2035 demand, a change that is almost entirely attributable to large customers.

This trend is not isolated to the Southwest: it is national in scope and scale. Multiple public studies suggest that rapid near-term growth could lead to a two- to three-fold increase in data center loads by the end of the decade:

- In a 2025 Grid Strategies report, the study states “Electricity usage is forecast to grow by an average of 5.7% per year over the next five years” and that “Data centers are the largest driver of demand and energy growth, accounting for about 55% of demand growth in utility load forecasts”
- A 2026 study published by EPRI, the findings reports that “In 2024, total U.S. data center nominal IT capacity is estimated to be 35 to 44 GW... By 2030, EPRI’s scenarios for the realization of planned and announced projects result in a range of 56 to 132 GW U.S. total nominal capacity. ”[6]

The trend of accelerating load growth is also apparent in recent demand forecasts published by utilities across the Western Interconnection. The effect of progressive increases in utility demand forecasts across the broader western region is illustrated in Figure , which shows the combined non-coincident peak demand forecasts for CAISO and select large western utilities in the West based on their most recent published forecasts at different moments in

Figure 3-2. Evolution of peak demand forecasts for large Western utilities since 2022



Represents sum of non-coincident peak demand for following jurisdictions: APS, CAISO, EPE, NVE, Pacificorp, PGE, PNM, PSCo, PSE, and TEP. Key updates by vintage:

- 2023: APS, CAISO, Pac, PNM, PSE
- 2024: CAISO, NVE, Pac, PNM, PSCo
- 2025: CAISO, EPE, Pac, PSE
- ***2026 (expected): APS, CAISO, NVE, PNM, TEP***

[6] Available at: https://powering-intelligence.epri.com

time.[7] Between 2022 and 2025, the compound annual growth rate among this group increased from just over 1% per year to 2.5% per year, resulting in an additional 10 GW of growth by 2035.

The challenges posed by the rapid growth of large customers are multifaceted:

- **Development Pace:** meeting the rapid pace of load growth requires a correspondingly rapid pace of new resource development, which creates strain upon global supply chains, local permitting processes, and a range of steps in the development process in between.
- **Forecast Uncertainty:** while the current pace of growth is rapid, long-term forecasts are subject to a heightened level of uncertainty; this uncertainty creates a confounding challenge for utilities making long-term investments to meet near-term growth;
- **Load Shape:** data centers and other large customers typically have relatively high "load factors" compared to residential and commercial customers, meaning that their loads are flatter throughout the day and year. As these loads become a growing share of the system, portfolios must be designed to account for round-the-clock needs of large customers.

3.2.2. Evolving Generation Mix

Due to wide-ranging technical, economic, and political forces, the composition of the generation mix is quickly shifting. Throughout the system, aging fossil generation resources are approaching the ends of their useful lives. In turn, the new resources added to the system to meet growing needs comprise a heterogenous mix of technologies, including natural gas, wind, solar, energy storage, and various demand-side resources. The transition of the electricity system to a more diverse mix of resources introduces new complexities to planning for resource adequacy.

For the purposes of describing the effects of different types of generation resources upon resource adequacy, generation resources can be classified into three broad categories:

- **"Firm"**: resources that can produce at or near maximum capacity for sustained periods of time, except when unavailable due to plant outages. Examples include nuclear, coal, and natural gas.
- **"Variable":** resources whose output varies hour by hour, typically as a function of meteorological conditions. Examples include wind and solar.
- **"Energy-limited":** resources with constraints on how long (and sometimes how often) they can generate at full capacity due to constraints that limit the amount of energy they can produce. Examples include hydroelectric generation, energy storage, and demand response.

Historically, most electricity systems have consisted primarily of firm resources, but as the penetrations of variable and energy-limited resources grow, their implications for resource

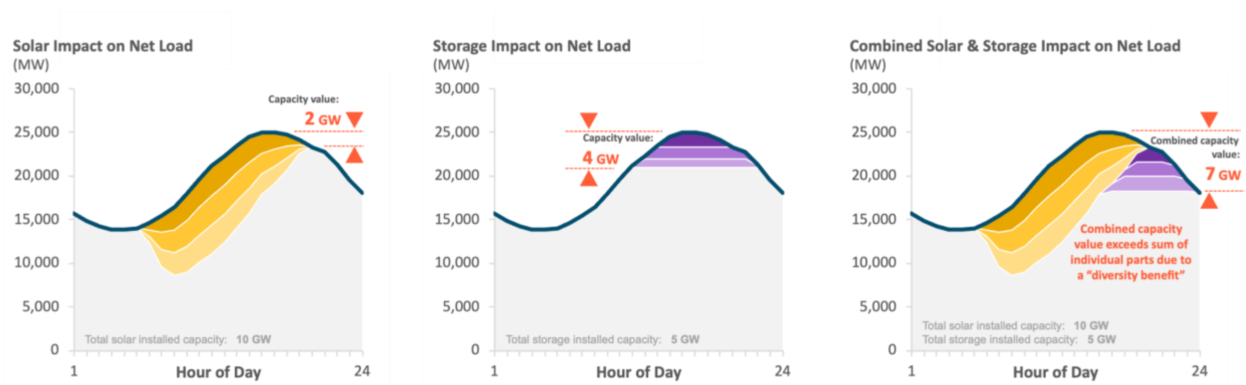
[7] While this graphic provides clear evidence of the trend of accelerating growth, it is also a lagging indicator: because many utilities release official load forecasts with integrated resource plans published on two- or three-year cycles, the forecasts included in the diagram above do not necessarily reflect each utility's most current expectations for load growth.

adequacy become significant. The contributions of variable and energy-limited resources differ from traditional firm resources in three important ways (illustrated in Figure 3-3.):

1. Because variable resource output is often lower than rated capacity during the periods in which supply is most constrained, the contribution of variable resources to resource adequacy is typically lower than their rated capacity. Further, as their penetration increases, the highest "net load" (load minus variable resource production, and a reasonable proxy for reliability risks) shifts away from system peak demand. In turn, this drives a "saturation effect" where the marginal value of variable resources decline with scale.
2. Because energy-limited resources have a finite ability to generate energy (e.g. a four-hour battery operated at full capacity will exhaust state of charge in four hours), they are also subject to saturation: as successive tranches of storage flatten net peak demand, the next tranche of storage must dispatch over a longer period to have the same effect.
3. The declining marginal value of both variable and energy-limited resources may be partially offset by the presence of interactive effects among different resources, often described as a "diversity benefit": a portfolio of complementary resources can provide a contribution to resource adequacy that exceeds the sum of its individual parts. The nature and size of this effect will vary based on the combination of resources (and can even be negative).

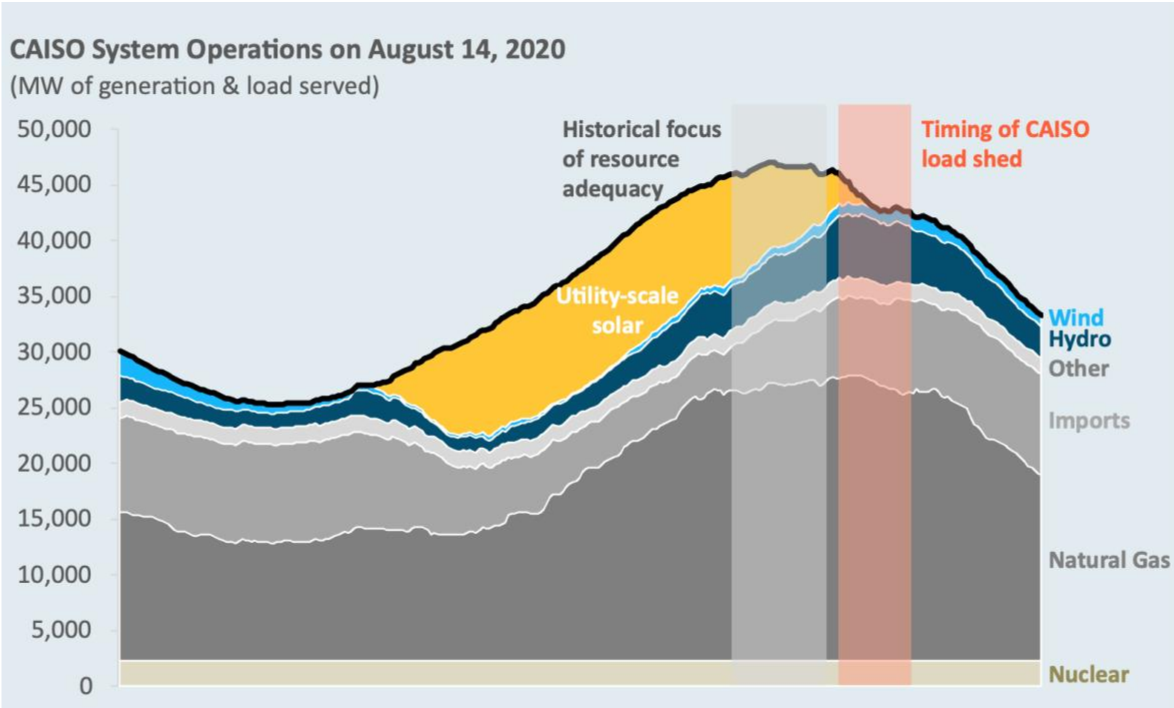
The underlying mechanism at the root of these complex, dynamic effects is the fact that increasing penetrations of both variable and energy-limited resources cause the periods of greatest reliability risk to shift away from the traditional peak period. As risk shifts or extends towards periods where a resource's availability is diminished, its marginal value declines; as risk shifts or extends into periods where a resource's ability is increased, its marginal value increases.

Figure 3-3. Illustrative impacts of solar and energy storage upon net load



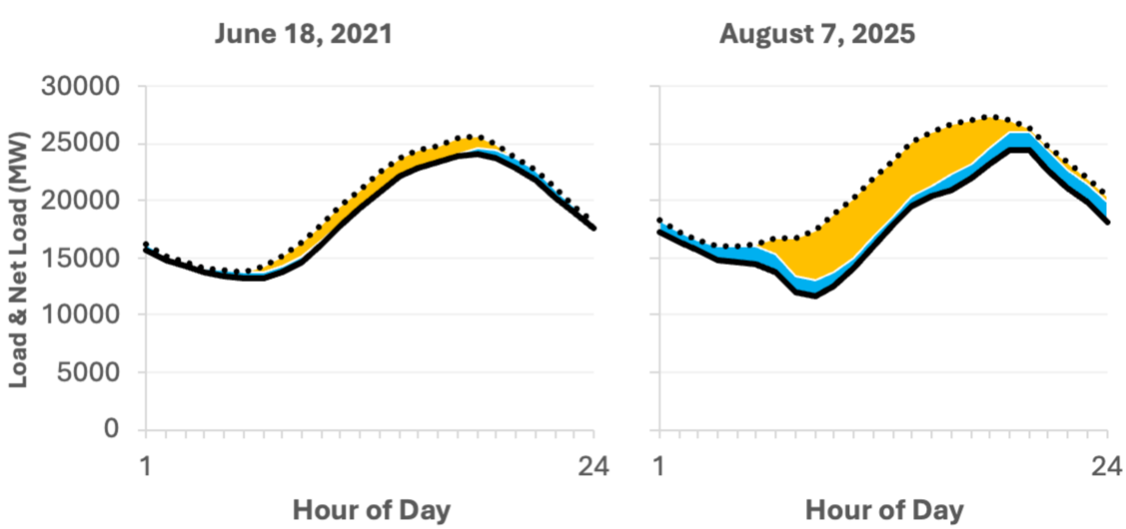
The August 2020 blackouts in California, highlighted in the 2021 study, remain the best real-world illustration of the shifting of reliability risks at higher penetrations of variable resources. Figure , developed from data published by CAISO, highlights the changing nature of resource adequacy risks under increased penetrations of solar; the period of the day during which load shedding was required occurred after the traditional peak period that has historically been the focus of resource adequacy planning.

Figure 3-4. CAISO system operations on August 14, 2020



Due to the large amount of solar generating capacity added in the Southwest region over the last five years, the same evening-peaking net load phenomenon is now also apparent. Figure compares the load and net load curves for the region on the regional peak days in 2021 and 2025, illustrating how the increasing penetration of solar has shifted the net load peak – and, by extension, the region's reliability risk, into the evening.

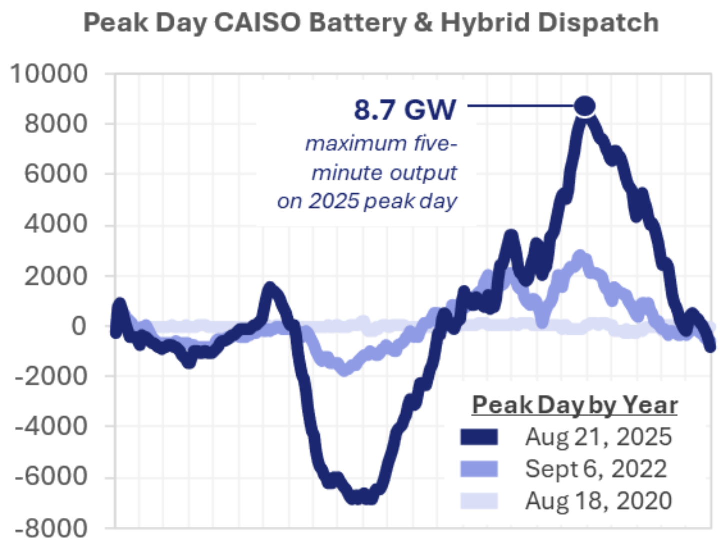
Figure 3-5. Load & net load curves for the Southwest region on regional peak days, 2021 and 2025



The real-world impact of energy storage on electricity systems is also now readily apparent. Since 2021, energy storage has matured from a technology in the early phases of commercial deployment (XX GW installed nationally at the end of 2021) to a proven resource at grid scale (XX GW at the end of 2025). Nowhere is its current impact on grid operations and its contribution to resource adequacy greater than in California, where battery storage resources in CAISO reached a five-minute maximum output of nearly 9 GW during the net peak period and into the evening on the day of the highest electricity demand (see Figure).

While significant amount of storage in the California system is now playing a key role in grid operations, the penetration is quickly approaching levels where the saturation effects described above are expected to emerge in the near future. The most recent analysis published by the California Public Utilities Commission projects that the marginal capacity value of storage will decline from 92% in 2026 to 75% by 2028 and 22% by 2030 as "critical hours spread to late afternoon and later into the night, contributing to storage ELCC declines."[8]

Figure 3-6. Dispatch of CAISO energy storage resources on select peak days



As the penetration of renewables, storage, and other non-firm resources continue to grow, so will the prominence of these complex dynamics. One of the implications that follows from these evolving challenges is that the timing of reliability risks will continue to shift towards periods when non-firm resources are not available – often periods of lower renewable production. During these periods, firm generation is the remaining resource that can dispatch at full capacity for prolonged periods. While the amount of firm resource capacity needed will vary from system to system, the essential role of firm capacity in maintaining resource adequacy – even in electricity systems with very high penetrations of renewables and storage – has been identified by numerous studies, including:

- *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California*, a study completed by E3 in 2019;
- "The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation" (Sepulveda et al.), published by researchers at the Massachusetts Institute of Technology;

[8] Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/reliability-filing-requirements_lses-2024-26_irp-plans_20260210.pdf

- *Net Zero America*, led by researchers at Princeton University to study pathways to meet a "net zero" carbon target for the United States by 2050;
- The *Los Angeles 100% Renewable Energy Study*, completed by the NREL to develop plans that would meet the City of Los Angeles' 100% renewable goals; and
- "Clean Firm Power is the Key to California's Carbon-Free Energy Future," a study co-funded by the Environmental Defense Fund and the Clean Air Task Force.

In many of these studies, the presence of firm resources alongside large penetrations of wind, solar, and storage is essential to the reliability of the system.

3.2.3. Headwinds Facing Resource Development

While resource needs are growing with increasing loads and the generation mix continues to evolve, utilities and project developers are also facing a more challenging environment to bring new resources online. Multiple sources indicate that the rates of project delays and cancellations and the lead times for new project development have increased in the past several years:

- A press release issued by the Energy Information Administration (EIA) at the end of 2025 reported that "[i]n the third quarter of 2025, solar projects representing about 20% of planned capacity reported a delay," a reduction from the highest rate of delay (25% in Q3 2024) but notably higher than the rates observed in 2020 (10-15%).[9]
- Experts at the Electric Power Research Institute (EPRI) reported that as of mid-2025, gas turbine manufacturers were typically quoting delivery lead times of up to five to seven years for new units, a considerable increase over historical norms.[10]
- A 2025 report published by Lawrence Berkeley National Laboratory (LBNL) reports that across a sample of 1,161 projects in service between 2009 and 2024, the length of time between projects securing an interconnection agreement and achieving commercial operations has increased from "…11 months for projects built in 2007, 19 months in 2015, and 35 months for those built in 2024."[11]
- An analysis by Cleanview, a market intelligence platform, reports that "…1,891 power projects with a combined 266 GW of generation capacity have been canceled in 2025—equivalent to roughly one-quarter of America's entire current electricity generation capacity."[12]

These "headwinds" are directly linked to the observed rapid increases in energy demand at a national scale, which has placed additional pressure on many of the processes and necessary steps

[9] Available at: https://www.eia.gov/todayinenergy/detail.php?id=66604

[10] Available at: https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply

[11] Available at: https://emp.lbl.gov/sites/default/files/2025-12/Queued%20Up%202025%20Edition%20-%2012.15.2025.pdf

[12] Available at: https://cleanview.co/content/canceled-projects-report

to develop new resources. Multiple factors contribute to the protracted timelines for new resource development and the increasing costs for new resources, including:

- **Interconnection study processes,** which have become increasingly complex and time-consuming as the volume of projects in interconnection queues has grown and system impact analyses have become more rigorous.
- **Permitting processes,** which often require coordination across multiple jurisdictions and can introduce multi-year timelines due to environmental review, siting challenges, and stakeholder engagement requirements
- **Supply chain constraints,** which are contributing to both longer backlogs for specialized equipment and rising project costs, particularly for transformers, gas turbines, and other critical grid components.
- **Financing and market conditions,** which have increased the cost of capital relative to historically low levels in 2020 and, in some cases, have contributed to project delays or cancellations as developers reassess project economics.
- **Workforce and labor constraints,** which are limiting the availability of skilled labor necessary for engineering, procurement, and construction, thereby extending project schedules and increasing development risk.

Collectively, these factors contribute to longer and less predictable development timelines, increasing the risk of delays in the development of resources needed to ensure reliability.

3.2.4. Fuel Supply Constraints

In the Southwest region, natural gas power plants represent a large share of the region's total installed capacity today (roughly 17 GW of a total of 30 GW) and play a key role in ensuring reliability within the region. In order to do so, gas power plants rely on pipeline systems for the "just-in-time" delivery of fuel.

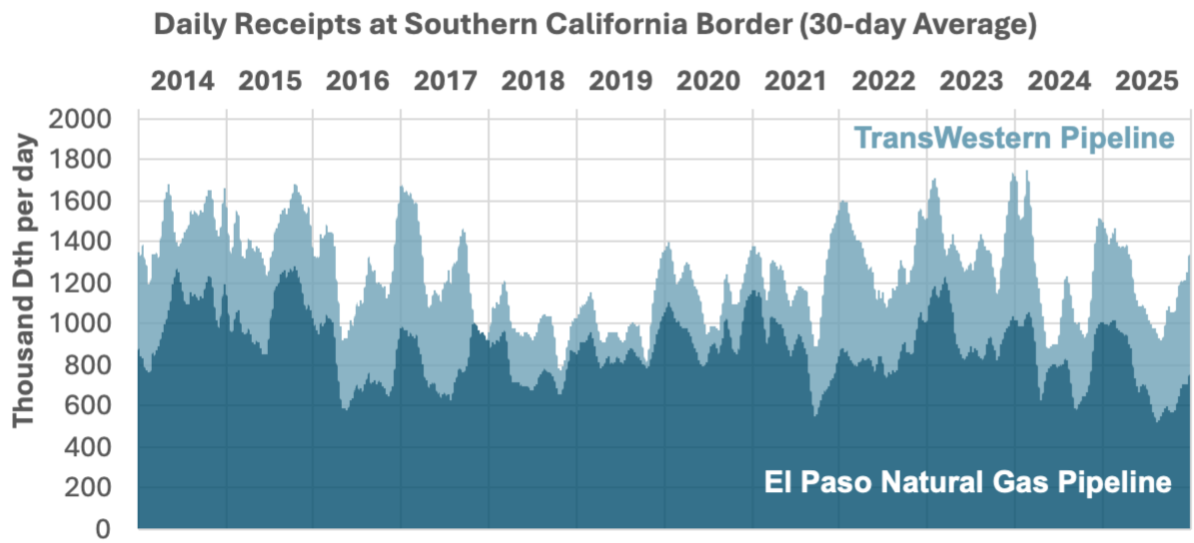
There are two major interstate pipeline systems in the Southwest region: the El Paso Natural Gas and TransWestern pipeline. The two pipeline systems deliver gas from the Permian and San Juan supply basins to end users in Arizona and New Mexico, as well as to the SoCalGas pipeline system at the California border.

To transport gas to natural gas power plants, electric utilities in the Southwest typically contract for "firm service" on the interstate pipeline systems. These contracts provide each utility with priority access to the pipeline to transport a prescribed daily volume of natural gas, typically sized by each utility to ensure it can adequately supply its portfolio of gas-fired resources. These arrangements allow utilities to ensure their natural gas resources can operate when needed for reliability.[13]

[13] In contrast, in regions where natural gas generators are not served under firm service – and rely on "interruptible service" instead – a lack of pipeline capacity and the corresponding inability to deliver natural gas to power plants has been identified as a major driver of reliability risk.

Ensuring resource adequacy in the region will require utilities to right-size their commitments for firm capacity on the pipeline system for their current and future natural gas needs. On today's system, utilities have limited flexibility to adjust their subscriptions: postings to the "Electronic Bulletin Boards" (EBB) on the two pipeline systems indicate that existing pipelines are nearly fully subscribed today. Further, despite its aggressive clean energy policies, the state of California has not observed a notable decline in its demand for natural gas, and the two pipeline systems continue to be utilized to transport high volumes of natural gas to the Southern California border (see Figure).

Figure 3-7. Daily natural gas receipts at the Southern California border from the two interstate pipeline systems in the Southwest



3.2.5. Climate Uncertainty & Extreme Weather

Concurrent with these changes to customer loads and energy supply, climate change is impacting weather system fundamentals, which has implications for electricity demand and resource availability. Scientific consensus, as captured in the Intergovernmental Panel on Climate Change's (IPCC) *Sixth Assessment Report*, concludes that:

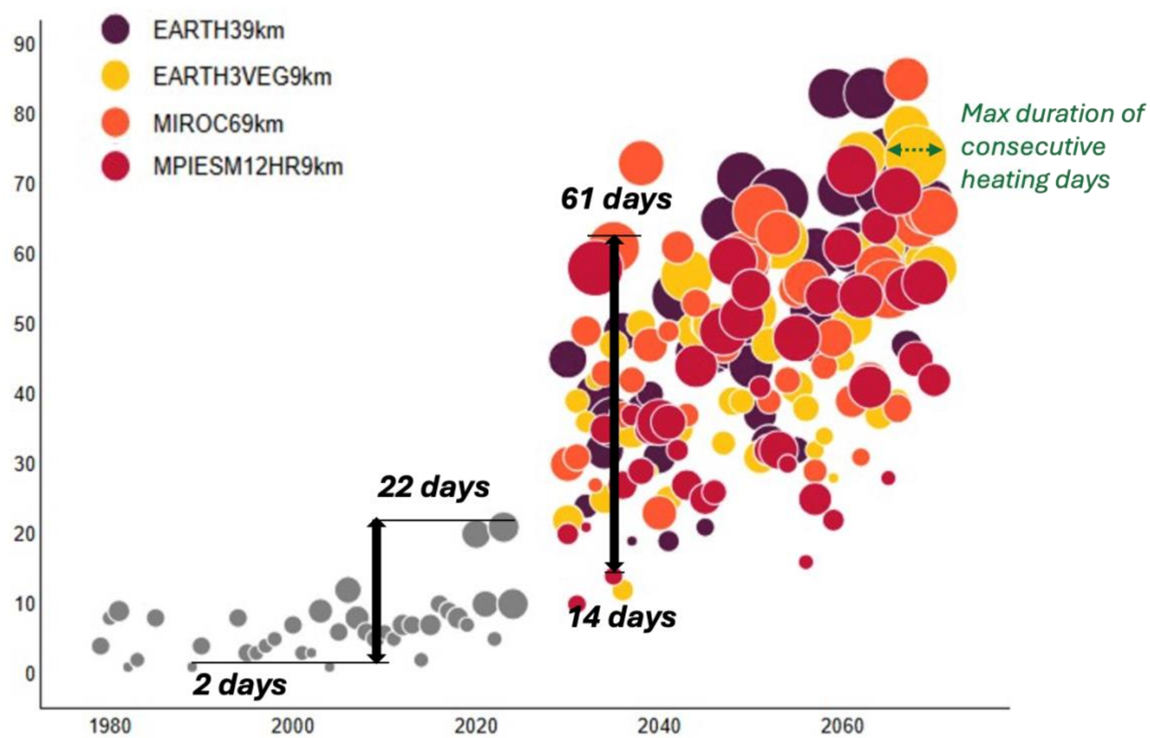
> "[g]lobal surface temperature will continue to increase until at least mid-century under all emissions scenarios considered. Global warming of 1.5°C and 2°C will be exceeded during the 21st century unless deep reductions in CO2 and other greenhouse gas emissions occur in the coming decades."[14]

The impacts of these global trends are far-reaching; the effects are expected to include "increases in the intensity and frequency of hot extremes, including heat waves (*very likely*), and heavy precipitation (*high confidence*), as well as agricultural and ecological droughts in some regions (*high confidence*)." Such increases appear across multiple General Circulation Models (GCM), often coupled with downscaling techniques to produce regional projections of future weather. Figure 3-8

[14] IPCC Sixth Assessment Report

compares the historical observed duration of summer heatwaves in the Southwest (defined as consecutive days reaching a temperature of 110 F or above in Phoenix) with projections of similar events for four GCM models (downscaled to the Southwest region). This comparison indicates both that (a) climate modeling indicates that the length of heatwave effects in the Southwest is expected to increase, while (b) there remains a significant degree of uncertainty – even in the near term – regarding the frequency and duration of temperature extremes.

Figure 3-8. Historical and projected frequencies of consecutive hot summer days (Phoenix temperature above 110F)



3.3. Best Practices for Resource Adequacy Planning

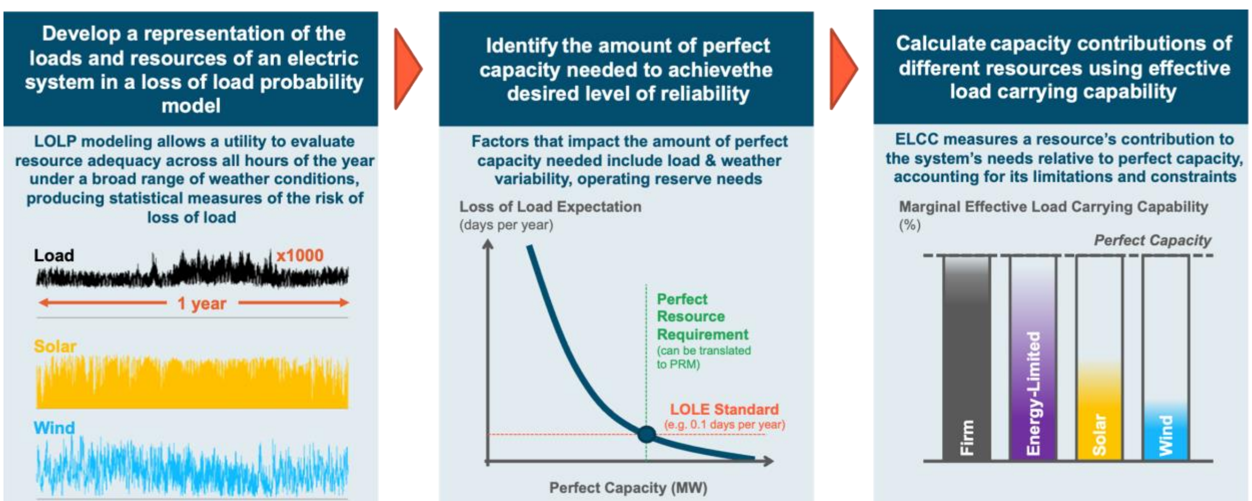
Planning a portfolio capable of serving loads across a wide range of potential conditions – despite the increasing complexity of the system, heightened levels of uncertainty, and the rapid pace of change – requires sophisticated analytical techniques to quantify the needs of the system, the availability of generation resources, and the resulting risks to reliability. The most widely accepted type of model for this type of analysis is **loss-of-load-probability (LOLP) modeling**, which relies on probabilistic and stochastic simulation techniques to evaluate resource adequacy across a broad range of possible conditions. In so doing, LOLP models identify the so-called **"critical periods"** in an electricity system: the conditions under which the system is most likely to experience resource deficiencies that may ultimately lead to the need to curtail firm electric load.

Designing the system to perform during these critical periods has always been the primary challenge of resource adequacy. Historically, those critical periods coincided almost exclusively with peak load, but increasingly, critical periods will occur at different times of day and year due to combinations of high load and low resource availability. The ability to identify such periods is foundational to all aspects of planning an adequate portfolio. At its most foundational level, a robust framework for resource adequacy requires three components:

1. Development of a **loss-of-load-probability model** that can simulate the availability of loads and resources on an hourly basis across a wide variety of weather conditions to identify periods in which an electricity system is vulnerable to reliability risks;
2. Derivation of a **total capacity requirement** that reflects the amount of "perfect capacity" needed to achieve an acceptable level of reliability (this is often subsequently translated into a **"planning reserve margin" requirement**); and
3. Application of an **effective load carrying capability (ELCC)** accounting framework to measure the contribution of each resource (or portfolio of resources) towards the total capacity requirement.

These best practices, summarized in Figure , guide the modeling approach used in both the near-term and long-term assessments to evaluate resource adequacy across the region.

Figure 3-9. Three foundational pillars underpinning a robust approach to resource adequacy



The 2021 study provides a more extensive description of resource adequacy best practices and their application, and most of the concepts and details remain equally useful today. Subsequent E3 publications, as well as a growing body of literature produced by others in the industry, continue to reaffirm the importance of a rigorous time-sequential LOLP modeling approach to evaluate resource adequacy. Key publications include:

- Redefining Resource Adequacy for Modern Power Systems (ESIG, 2021)[15]

[15] Available at: https://www.esig.energy/wp-content/uploads/2022/12/ESIG-Redefining-Resource-Adequacy-2021-b.pdf

- Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches (EPRI, 2022)[16]
- Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation (ESIG, 2023)[17]
- New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements (ESIG, 2024)[18]
- Resource Adequacy for a Decarbonized Future (EPRI, 2024)[19]
- Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets (E3, 2025)[20]

Adoption of these best practices for resource adequacy planning is becoming increasingly common across the industry. In the Southwest, the current methods by the region's major utilities – the sponsors of this study – each have developed LOLP models of their system, have used those tools to derive PRM requirements based on statistical loss-of-load metrics, and have adopted ELCC as the primary method for resource accreditation.

[16] Available at: https://www.epri.com/research/products/000000003002024368
[17] Available at: https://www.esig.energy/wp-content/uploads/2023/02/ESIG-Design-principles-capacity-accreditation-report-2023.pdf
[18] Available at: https://www.esig.energy/wp-content/uploads/2024/03/ESIG-New-Criteria-Resource-Adequacy-report-2024a.pdf
[19] Available at: https://www.epri.com/research/products/3002027832
[20] Available at: https://www.ethree.com/wp-content/uploads/2025/08/E3_Critical-Periods-Reliability-Framework_White-Paper.pdf

4. Near-Term Resource Adequacy Assessment

The near-term resource adequacy assessment provides a comprehensive outlook for resource adequacy in the Desert Southwest region across the coming decade by applying the best practices described in Section 3. This section of the report presents the scope, the modeling approach, key inputs and assumptions, and technical results.

4.1. Scope of Analysis

Much like the 2021 study, the scope of the near-term assessment focuses on an evaluation of regional resource adequacy by aggregating load forecasts and resource portfolios provided by individual utilities to the regional level. Using loss-of-load-probability modeling, the analysis uses stochastic chronological simulations of loads and resources across the region. While the primary purpose of the near-term assessment is to evaluate whether utilities' plans will meet regional resource adequacy needs, the supporting analysis provides answers to a range of questions that establish a comprehensive outlook for regional resource adequacy:

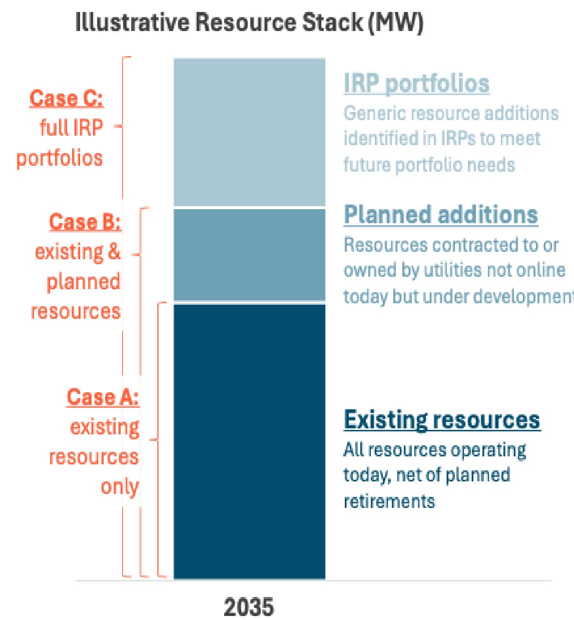
The near-term reliability outlook presented here uses load forecasts and resource portfolios provided by utilities in early 2025. Since that time, utilities have continued to update load forecasts and adjust resource plans in response to continuously changing conditions. For this reason, these results do not reflect the most current outlook for loads and resources within the region, but nonetheless serve as a useful directional indication of the relative scale of resource needs and provides validation that utility planning processes continue to identify resource portfolios capable of meeting regional reliability needs.

1. What is the current and future need for capacity in the Southwest region to maintain reliability across the region with a loss of load expectation of no more than 0.1 days per year ("one day in ten years")?
2. How much new effective capacity will be needed to ensure this level of reliability can be maintained?
3. To what extent will resources that are already under development today satisfy a portion of the need for new resources?
4. To what extent are utilities' resource plans positioned to meet regional resource adequacy needs?
5. How will resource adequacy risks evolve over the coming decade with anticipated changes in loads and resources?
6. How will the contributions of different technologies towards meeting the region's needs during the periods of greatest risk change?

To answer these questions, the near-term resource adequacy assessment includes the following analysis:

- Calculation of reliability statistics for three resource portfolios for each year from 2025-2035: (1) existing resources (net of retirements); (2) existing and in-development resources; and (3) full utility resource plans (see Figure 4-1);
- Close inspection of loss-of-load events observed in the simulations to provide insight into key drivers of reliability risk and the performance of different resources during critical risk periods;
- Evaluation of capacity credits for different technologies across the modeling horizon; and
- Sensitivity analysis on key uncertainties that could impact regional reliability.

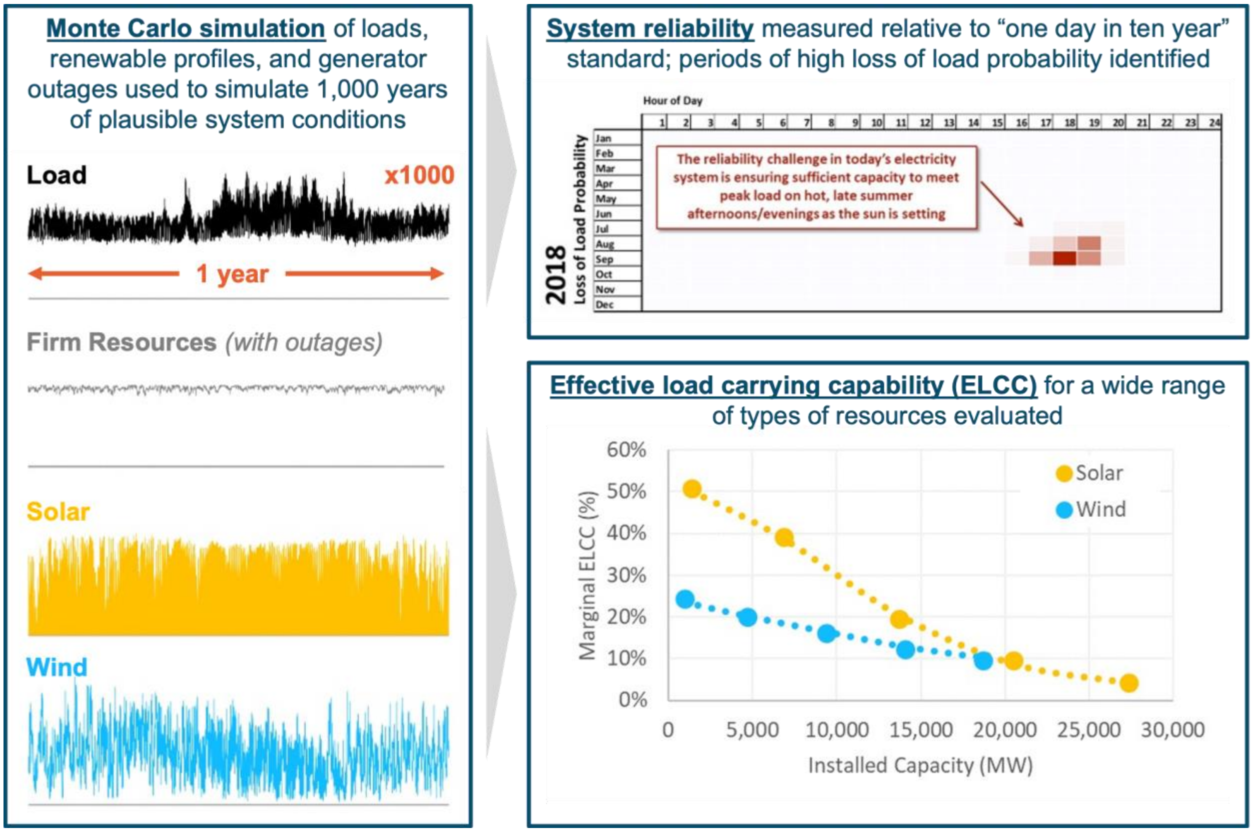
Figure 4-1. Three portfolios evaluated in near-term assessment



4.2. Modeling Approach

This phase of analysis utilizes **Renewable Energy Capacity Planning (RECAP)** model, developed and maintained by E3, to conduct LOLP modeling of the southwest region. RECAP simulates the availability of electric supply to meet demand across a broad range of conditions on a time-sequential basis, accounting for weather-driven variability of electric demand and weather-dependent resources like wind, solar, and hydro; power plant forced outages, and energy limitations and operating constraints for resources like storage and demand response. These simulations determine the likelihood and magnitude of loss of load – energy demand that cannot be served due to an insufficiency of capacity or energy – and provide the basis for calculating the PRM.

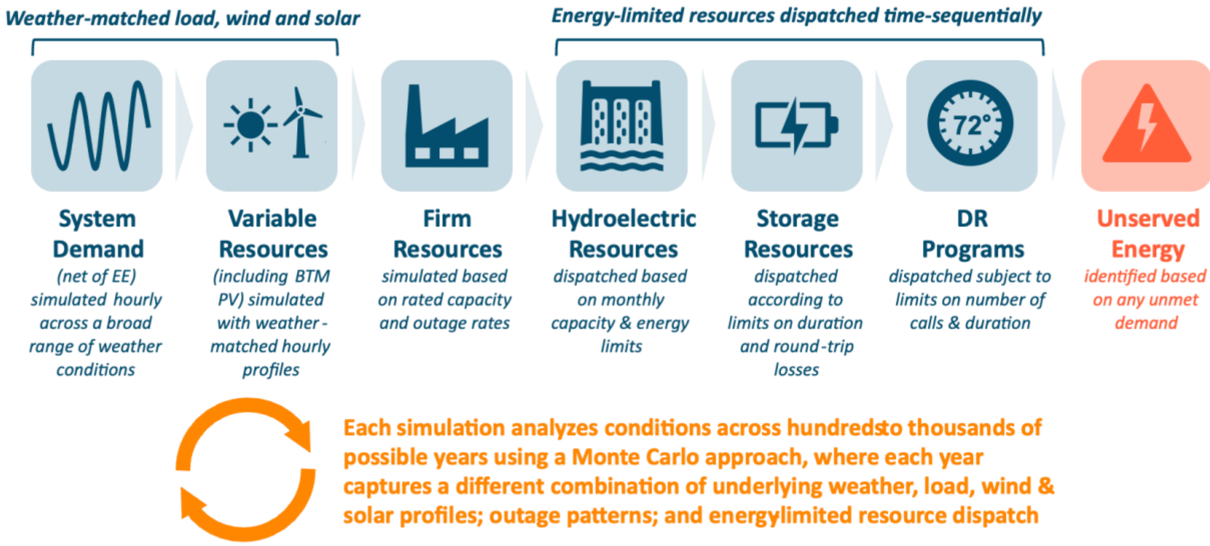
Figure 4-2. Overview of E3's RECAP model



RECAP simulates hundreds of "years" of potential conditions using stochastic techniques to appropriately capture the risk of tail events (e.g., higher load and lower renewable output than expected).[21] RECAP simulates balance between system demand and available generation in each hour of a year and repeats this process hundreds of times with different system conditions (see Figure). This ensures that RECAP captures a wide distribution of potential outcomes, including unlikely tail events that may not occur in a "typical" year. Relevant correlations are preserved within the model to ensure linkage among load, weather, and renewable generation conditions based on historical observations.

[21] In this approach, each "year" represents a different realization of conditions on the Southwest region over the course of a year. Factors that will vary from one "year" to the next include underlying weather patterns – and by extension, load and renewable profiles – power plant outages, and energy-limited resource dispatch.

Figure 4-3. RECAP simulation methodology



Through this simulation process, RECAP calculates the usual suite of statistical metrics produced in LOLP modeling to characterize the frequency, magnitude, and duration of potential reliability events (LOLE, LOLH, EUE, and others). Additionally, RECAP can be used to calculate common "derivative" metrics, including the planning reserve margin and ELCCs for individual resources.

4.3. Key Assumptions

Developing a representation of the Southwest region in an LOLP model requires a broad range of inputs to characterize the range of expected system demands and the capabilities of the available generating resources. The inputs and assumptions needed for this analysis are summarized in Table 4-1.

Table 4-1: Summary of key inputs for RECAP

Module	Inputs Needed
System Demand	• Annual energy demand • Annual 1-in-2 peak demand • Hourly profiles corresponding to a wide range of weather conditions (20+ years) • Minimum operating reserve requirements
Firm Resources *(e.g. nuclear, coal, gas, biomass, geothermal)*	• Seasonal capacity rating by resource • Forced outage rate by resource • Mean time to repair by resource
Variable Resources *(e.g. wind, solar)*	• Installed capacity by resource • Hourly profiles for multiple years, ideally including multiple years of overlap with hourly load profile data
Hydroelectric Resources	• Installed capacity by resource • Monthly/daily energy budgets across a range of plausible hydro conditions • Minimum output levels by month/day • Sustained peaking limitations by month/day
Storage Resources *(e.g. batteries, pumped storage)*	• Installed capacity by resource • Duration by resource • Charging & discharging efficiency by resource • Paired variable resource (for hybrids) • Interconnection configuration & rating (for hybrids)
Demand Response Resources	• Expected load impact by program • Limits on number of program calls (per year or per month) • Duration of calls

4.3.1. Demand Forecast

To produce a regional Southwest demand forecast, this study uses a bottom-up approach that involves three steps (see Figure 4-4): (1) collecting forecasts for annual energy demand from each participating utility and aggregating them to produce a regional forecast; (2) creating and applying hourly profiles for individual components of load to those annual demands in a manner that captures the seasonal and diurnal characteristics; and (3) aggregating the resulting shapes together to derive a total hourly load shape with a regional coincident peak demand. This section describes the demand forecast methodology in detail and the collaboration between E3 and the Southwest utilities.

Figure 4-4. Three-step process to develop hourly load inputs for resource adequacy modeling

Step 1: Develop Regional Energy Demand Forecast

As an input to this study, each sponsoring utility provided a demand forecast based on their outlook at the beginning of 2025. The total energy forecasts provided by utilities are segmented into the following categories:

- Existing end use demands, net of the projected impacts of incremental energy efficiency[22];
- Electric vehicle charging demands;
- New large customer demands; and
- Behind-the-meter solar generation (treated as a decrement to loads).

The total annual demand for electricity is determined by aggregating these utility-provided forecasts together and making an additional adjustment to account for the existing electric demands within the region that are not directly served by these utilities (typically small municipal utilities and cooperatives).

Step 2: Create and Apply Hourly Shapes

The segmentation described above allows the analysis to capture the impacts of these changing elements upon the regional shape of demand for electricity. Hourly shapes for each segment are developed using different approaches, summarized in Table 4-2.

Table 4-2. Description of load shaping approaches used for each segment

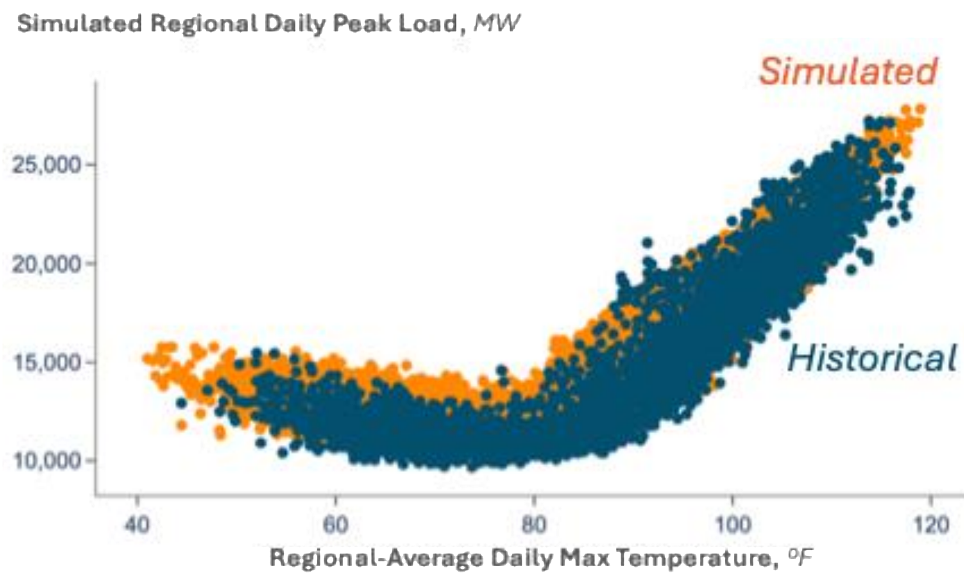
Load Segment	Load Shaping Approach
Existing End Use Demands	Neural network simulation over 45-year history (1970-2024) based on historical temperature (detrended for climate impacts) and electric demand data
Electric Vehicles	Hourly shape for a single year developed using E3's EVGrid modeling toolkit,[23] reflecting a combination of managed and unmanaged charging
New Large Customers	Hourly profile for a single year assuming 90% load factor and a daily shape that coincides with cooling demands (peaks in the day and lowers in the evenings).
Behind-the-Meter Solar PV	Hourly profiles simulated for 1998-2020 using NREL System Advisor Model based on representative locations across six major population centers

Among these four segments, the most important and consequential for the purposes of resource adequacy modeling the shape applied to existing end use demands, both because of their relative magnitude and sensitivity to extreme weather conditions. Robustly capturing the risks associated with extreme weather events that may not occur in a "typical" year requires development of demand shapes across a wide range of weather conditions. To create such a dataset, this study uses neural network regression techniques to simulate present-day electricity demands under an extended

[22] Energy efficiency forecast assumptions are provided by each sponsoring utility and is modeled as energy reduction in each hour across the entire year.
[23] For additional detail, see: https://www.ethree.com/tools/electric-vehicle-grid-impacts-model-2/

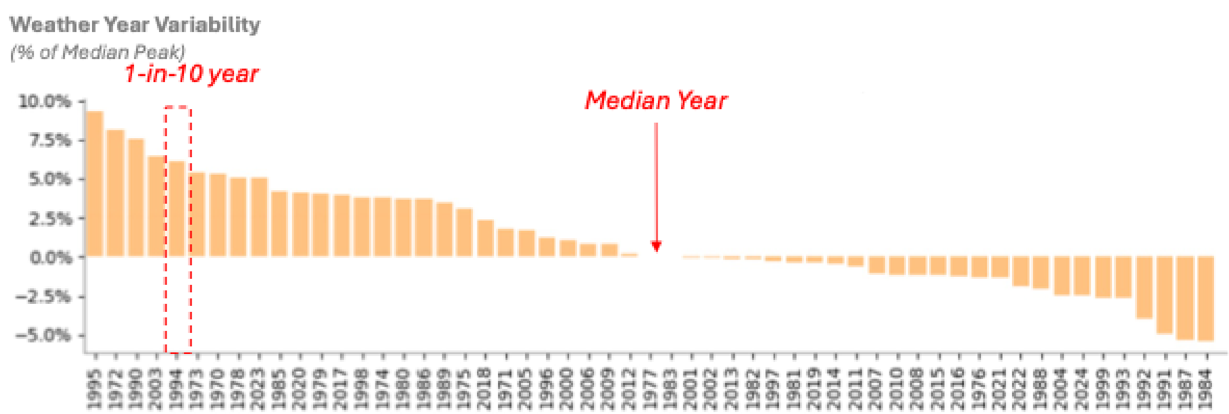
historical weather record.[24] This approach establishes a direct relationship between temperature at key population centers across the region and the corresponding electricity demand. This relationship is illustrated in Figure 4-5, which compares the 2024 actual daily peak and daily maximum temperatures against the simulated outputs from the neural network regression.

Figure 4-5. Historical and simulated weather and load data



Applying this to reanalysis weather data covering the period 1970-2024 produces a 45-year record of hourly demand shapes that reflects a range of typical, mild, and extreme weather conditions. Figure 4-6 represents the peak load variability observed across the 45 years ranked from highest annual peak load observed to the lowest.

Figure 4-6. Peak demand (relative to a "1-in-2" level) for each weather year simulated

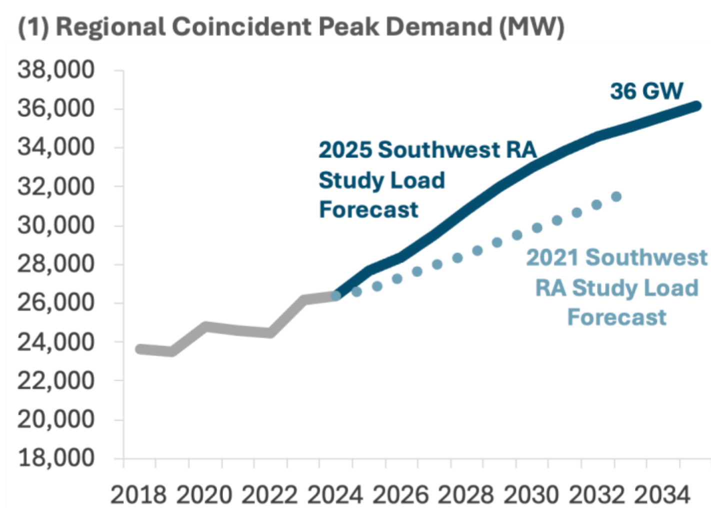


[24] The primary dataset used in this study is ERA5-LAND. As in the previous study, these historical temperature data have been "detrended" to account for the apparent underlying warming trends.

Step 3: Derive Regional Coincident Peak Demand Forecast

All the components described above are combined within RECAP to produce the total load for the Southwest. The resulting hourly profile produces a median peak load forecast for the region and produces a broader range of variability (representing 45 total weather years) needed for a robust assessment of resource adequacy. Figure 4-7 shows the peak load forecast for the full Southwest region present in this study. The figure also compares this study's peak load forecast compared to the 2021 study's peak load forecast. Between the two, the rate of growth is higher (2.7% per year in this study compared to 2.2% per year in the 2021 study).

Figure 4-7. Projected regional coincident peak demand based on utility forecasts



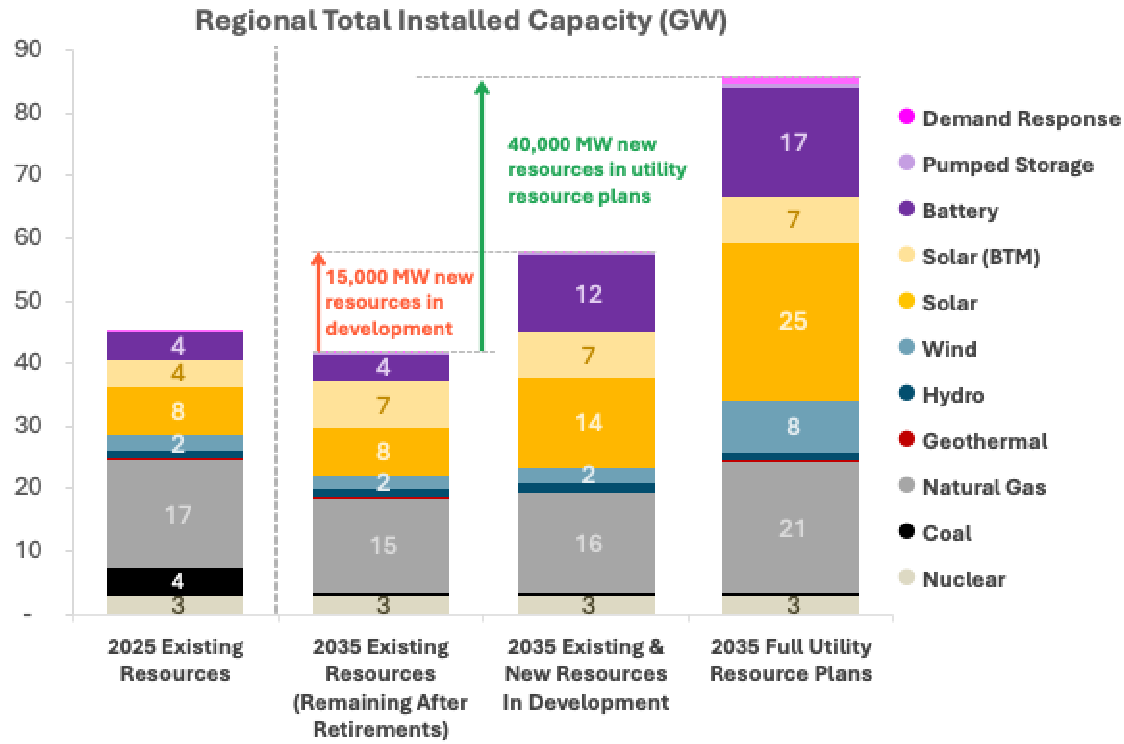
4.3.2. Resource Portfolios

Portfolios of electric generating resources analyzed for the near-term study are created through aggregation of resource data provided directly by the participating utilities. Over the course of the ten-year horizon, three portfolios are evaluated; each evaluation serves a specific purpose:

1. **Existing Resources Only (Remaining After Retirements):** how much additional effective capacity will be needed to meet load growth and replace retiring resources?
2. **Existing & New Resources in Development:** to what extent will resources already under development satisfy need for new capacity?
3. **Full Utility Resource Plans:** to what extent will utilities' resource plans, including generic future resource additions, enable the region to achieve an LOLE of 0.1 days per year or better (if successfully implemented)?

The installed capacity of existing resources in 2025, as well as for the three portfolios analyzed in 2035, are shown in Figure *4-8*.

Figure 4-8: Composition of resource portfolios evaluated in near-term assessment



> *In developing the portfolios for the purposes of this study, the utilities make several important underlying assumptions: first, that the transmission necessary to deliver new resources to loads is also constructed in a timely manner; and second, that the availability of natural gas transportation capability to serve the region's gas generators is not a constraint that limits their use. To the extent either or both of these preconditions are not met, the region may face additional resource adequacy risks not identified by the analysis in the near-term assessment, where these factors are not explicitly modeled.*

The availability of each specific resource included in each portfolio is represented in RECAP's stochastic simulations in a manner that reflects its characteristics and limitations, which generally vary by technology. The key factors that constrain each resource's availability, and the basis for assumptions used in this study, are provided in Table 4-3.

Table 4-3. Overview of data development process and availability representation of different technologies in study

<table>
<tr><th>Technology</th><th>Data Development and Availability Representation</th></tr>
<tr><td>Nuclear</td><td rowspan="3">• Maximum capacity varies seasonally with summer & winter capacity ratings provided by utilities
• Random forced outages simulated stochastically based on plant-specific rates provided by utilities</td></tr>
<tr><td>Coal</td></tr>
<tr><td>Natural Gas</td></tr>
<tr><td>Geothermal</td><td>• Maximum capacity specified by plant</td></tr>
<tr><td>Hydro [25]</td><td>• Monthly maximum capacity and energy budgets provided by WAPA for five hydro scenarios
• Hydro scenarios modeled stochastically based on probabilities provided by WAPA
• Hydro resources dispatched to flatten net load, subject to operating constraints</td></tr>
<tr><td>Wind</td><td>• Site-specific hourly profiles simulated from meteorological and turbine power data gathered from NREL's WIND Toolkit for the historical period 2007-2012</td></tr>
<tr><td>Solar</td><td>• Site-specific hourly profiles simulated using NREL's System Advisor Model (SAM) for the historical period 1998-2022</td></tr>
<tr><td>Battery Storage</td><td rowspan="2">• Dispatched to minimize loss of load, subject to capacity and energy limitations (and interconnection limitations for hybrid facilities)
• Random forced outages simulated stochastically using a generic 5% outage assumption</td></tr>
<tr><td>Pumped Storage</td></tr>
<tr><td>Demand Response</td><td>• Maximum capacity varies seasonally with summer & winter capacity ratings provided by utilities</td></tr>
</table>

[25] Represents large reservoir projects managed by Western Area Power Administration (WAPA). Pumped Storage Hydro would be considered as Storage.

4.4. Results

4.4.1. Regional Planning Reserve Margin (PRM)

As discussed in Section 3.3, one of the key components in the RA planning framework is to measure the total capacity need needed to achieve a one-day-in-ten-year loss of load expectation (0.1 LOLE) target. Under the load and resource assumptions in this study, maintaining a LOLE of 0.1 days per year in the Southwest requires a 12-13% PRM, expressed as the amount of perfect or effective capacity needed above the median peak load. This result is a direct output of the RECAP model that quantifies the quantity of perfect capacity in MW that is necessary to achieve the reliability target. Dividing this megawatt value by the 1-in-2 peak demand and subtracting one yields the percentage PRM requirement. Table 4-4 illustrates the relationship between the 1-in-2 peak, the total capacity need, and the resulting perfect capacity PRM.

Between 2025 and 2032, the region's 1-in-2 peak grows from 27,666, MW to 31,800 MW; meeting regional needs according to a 0.1 LOLE reliability target in 2032 requires 12-13% reserve margin (31,143 and 38,672 MW of effective capacity for 2025 and 2032 respectively).

While the absolute quantity of capacity needed grows, the relative requirement remains relatively stable and is consistent with the level of planning reserves identified in the 2021 study. The stability of this planning reserve margin throughout the horizon and across studies holds true because the amount of effective capacity needed is independent of the resources in the portfolio: "need" is calculated in a manner that only reflects the nature of electricity demand and operating reserves across all hours of the year.

Table 4-4. Planning reserve margin values for 2025 and 2032

	Peak Load (MW)	Total Capacity Need (MW)	Perfect Capacity PRM (%)
2025	27,666	31,143	13%
2032	34,564	38,672	12%

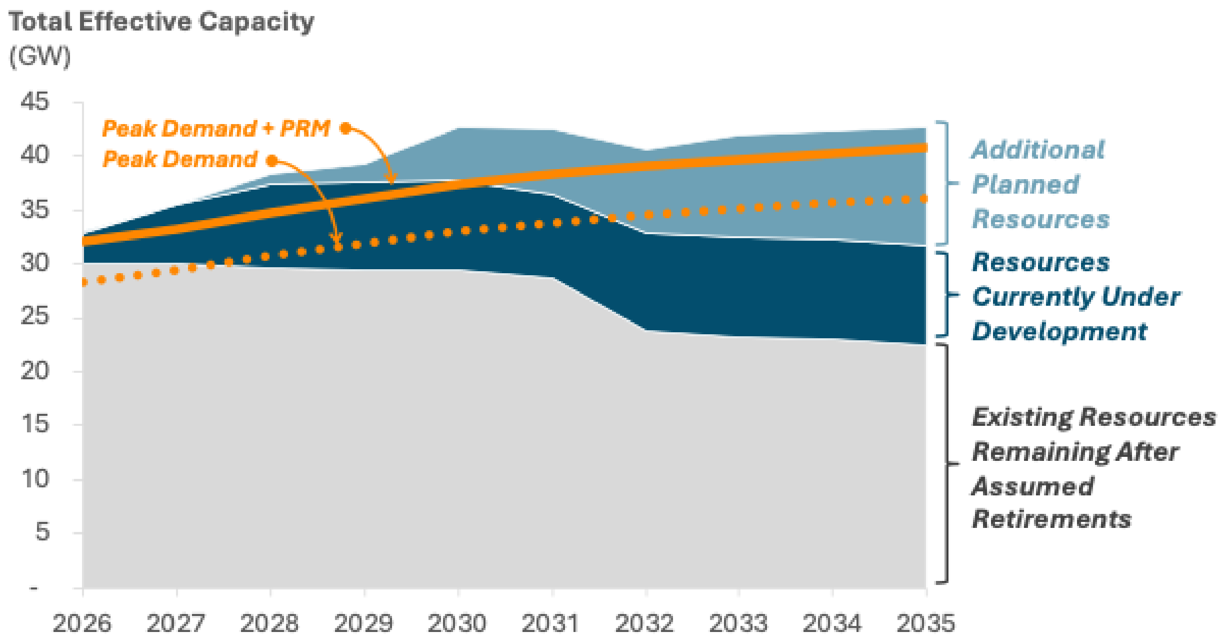
4.4.2. Outlook for Regional Load-Resource Balance

Figure shows the projected load-resource balance for the region based upon the load forecast and resource portfolio assumed used in this study. The figure highlights the increasing regional capacity needs with growing loads and the effective capacity provided by existing resources, resources under development, and generic resources included in utility plans.

- Over the next decade, the aggregated demand forecasts provided by utilities increase by 30%, or a total of over 8,000 MW. Incorporating a planning reserve margin of 13%, load growth increases the regional need for effective capacity by nearly 10,000 MW.

- At the same time, the retirements and expiring contracts of coal and natural gas plants assumed in this study result in the loss of approximately 8,000 MW of effective capacity.
- In conjunction, these two factors create a need for 18,000 MW of new effective capacity over the course of the next decade to maintain regional resource adequacy needs.
- Resources currently under development are poised to meet a portion of those needs, providing just over 9,000 MW of effective capacity and positioning the region to maintain load resource balance over the next several years.
- The additional generic resources included in utility plans are sufficient to close the remaining gap, creating some headroom in advance of planned resource retirements and satisfying the need for new capacity over the coming decade.

Figure 4-9. Projected regional load-resource balance based on utility plans current as of Q1 2025



While the rate of load growth and resource additions have both increased since the publication of the 2021 study, the overall balance of loads and resources ten years into the future remains similar: both the 2021 study and this study show a small margin of capacity above the minimum quantity needed to maintain a regional LOLE of 0.1 days per year. The implication of this consistency is that utilities' updates to their plans in response to accelerating load growth have identified solutions to preserve regional resource adequacy, despite the increasing complexity of the resource mix.

While the presence of a sustained resource deficit would be cause for concern – an indication that the physical limitations of the resources utilities plans would not allow the region to achieve an LOLE of 0.1 days per year – the presence of a margin of surplus does not necessarily indicate that utilities are planning to procure excess capacity due to a variety of factors not explicitly captured in this analysis:

- This analysis treats the region as a "copper sheet" with no internal transmission constraints, allowing resources located anywhere in the region to contribute to meeting all loads. Constraints on the transmission system may limit utilities' ability to utilize resources in this manner.
- This analysis assumes full fuel availability for gas, nuclear, and other fuel-burning resources in the region. Lack of supply in the regional fuel delivery system during critical periods may disrupt utilities' ability to generate power to meet the region's reliability needs.
- The analysis assumes that the dispatch of energy-limited resources (storage, hydro, and demand response) is perfectly orchestrated to maximize their value to regional resource adequacy; in reality, the dispatch of these resources may not align with these patterns due to utility-specific operational choices, market rules and processes, and imperfect information sharing. This, in turn, could result in tighter market conditions than simulated in this study.
- While this analysis adjusts the historical weather record to account for the past warming trends observed, it does not account for potential future load shape changes due to increased warming over the next decade. Increased frequency and severity of extreme heat events could place additional strain on resource adequacy. This risk is explored in several of the sensitivities presented in Section 4.4.5.

Further, while this analysis models resource adequacy at a regional level, the responsibility to ensure resource adequacy remains a utility function, not a regional one. Each individual utility establishes its own reliability target, evaluates the ability of resources to contribute to their own needs, and makes assumptions about the availability of "market support" from neighboring utilities based on their own independent assessment of risk. This approach is inherently unlikely to capture the full value of potential load and resource diversity across the region but remains the de facto method through which resource adequacy is planned and evaluated.

4.4.3. Evolving Drivers of Reliability Risk

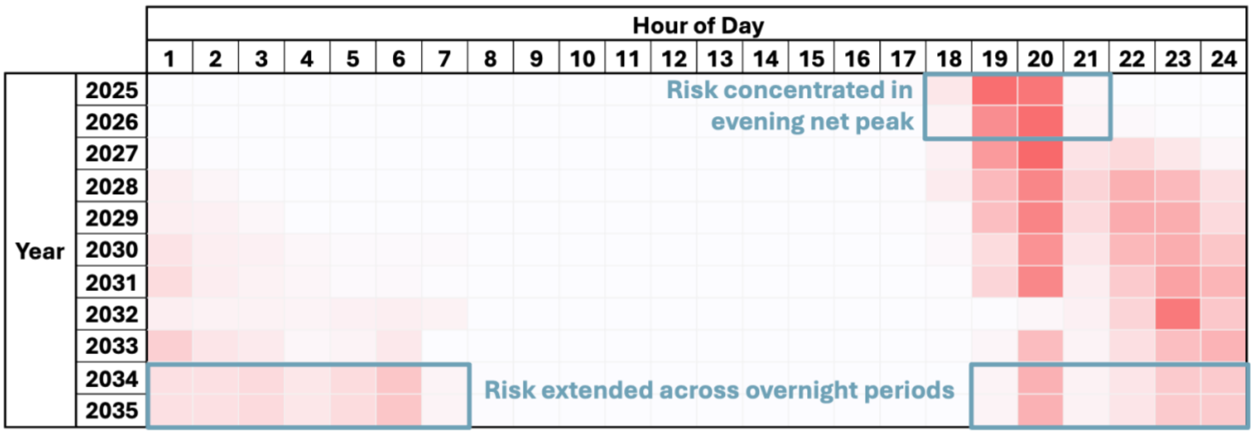
Utilities' plans include significant quantities of renewables and storage resources to help meet regional resource adequacy needs over the next decade: roughly half of the 2035 need for effective capacity is provided by firm resources, while the other half is provided by variable and energy-limited resources. As utilities add increasing quantities of renewables and storage, the periods of highest risk migrate from the afternoon peak periods to other times of the day. This transition is already underway, and will continue over the course of the next decade:

- Historically, the periods of greatest reliability risk occurred during peak demand conditions. In a system of predominantly firm resources, meeting the highest loads of the year – typically on the hottest summer afternoons – required the most generation capacity.
- Today, extreme summer days continue to drive the region's risk, but the timing of risk within the day has shifted due to the higher penetration of solar resources. Since the 2022 Study, the Southwest utility-scale solar fleet has increased from roughly 3 GW to 8 GW. With more solar output during the gross peak load period, today's risk has shifted to evening periods, 6-8pm.

- As the solar and storage additions continue, risk will shift deeper into the evening and nighttime hours. This continued transition is a reflection of the system becoming increasingly "energy constrained," as the greatest reliability risks occur during the periods when storage resources are most likely to be depleted after discharging during the evening.

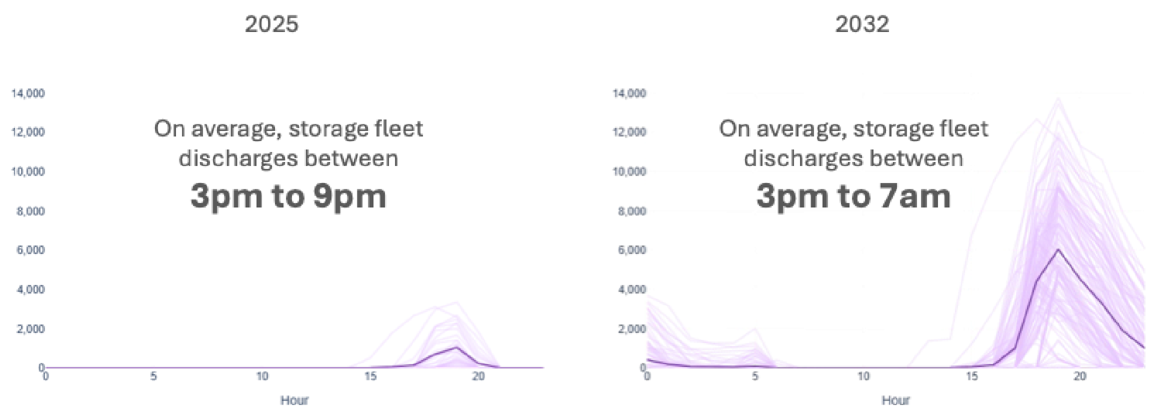
This progressive shift of loss-of-load risk deeper into the overnight period is shown in Figure 4-10 below, which illustrates how the year-by-year changes to loads and resources impact when loss-of-load is most likely to occur. All observed events occur in the summer season.

Figure 4-10. Progression of average loss-of-load risk by hour of the day, 2025 to 2035



The observed shifting of risk from the afternoon into the evening is a direct result of the increasing penetration of solar resources due to the well-documented "net peak." The subsequent extension of risk into overnight periods is a natural result of the increasing penetration of storage resources: at low penetrations, storage resources discharge during finite, short windows during the net peak period, but at higher penetrations, the discharge window for storage resources extends across broader periods as they serve a larger portion of loads. This contrast is shown in Figure 4-11, which contrasts summer discharge patterns for a small portfolio of storage resources in 2025 (roughly 4,000 MW) with a much larger one in 2032 (over 16,000 MW). As the discharge window for storage resources lengthens, the finite amount of energy stored is more likely to be exhausted.

Figure 4-11. Comparison of storage dispatch patterns to maintain reliability in 2025 and 2032

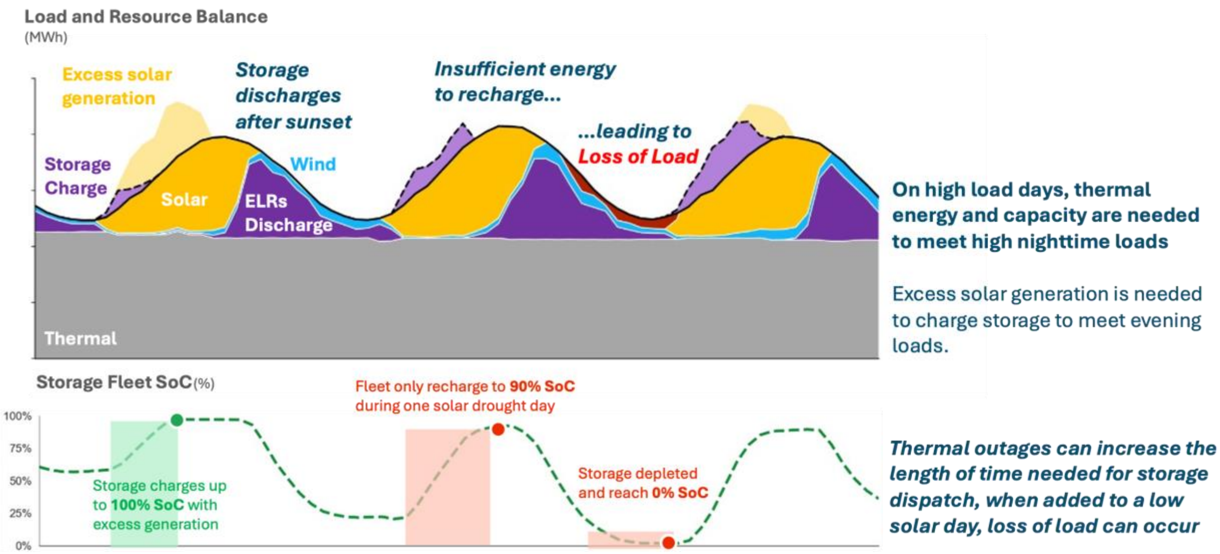


As the nature of loss-of-load risk shifts from periods when the instantaneous generating capacity is insufficient to serve loads to periods following the depletion of energy-limited resources, the system transitions from being “capacity-constrained” to “energy-constrained.” Figure 4-12, based on the modeling of 2035 utility plans, provides a specific example of how the depletion of storage state-of-charge across multiple days could eventually culminate in a longer loss of load event during the early morning hours.

- On the first day of the event, storage resources reach full state of charge during daylight hours; during the evening period, they are dispatched during the evening and overnight periods and reach a minimum state of charge of roughly 20%.
- During the subsequent day, the available surplus energy is insufficient for storage resources to fully recharge, and the fleet only reaches 90%.
- As a result, the region’s storage resources are fully depleted over the course of the next overnight period, and a loss-of-load event begins in the late evening hours and extends through the full overnight period until the next morning.

This event reflects an energy, rather than a capacity limitation, as the depletion of storage state of charge immediately precedes the realization of loss of load. Importantly, an additional MWh of generation (or a corresponding reduction of load) at any point in time from the late evening of day one to the early morning of day three would have directly reduced the size of this loss of load event.

Figure 4-12. Example of storage depletion in RECAP leading to an "energy-constrained" loss-of-load event



4.4.4. Resource Accreditation

The changing timing of critical periods is intrinsically linked to the capacity value that different types of resources provide to the system. The contribution of each technology to the system, measured using marginal ELCC, provides a direct relative measure of how much each resource contributes to resource adequacy at the margin. Changes to the marginal ELCC from 2025 to 2035, for each technology, are shown in Table 4-5. Technologies are subdivided into three categories (firm, variable, and energy-limited), a schema that groups together resources with similar characteristics and limitations.

- Firm resources (nuclear, coal, natural gas, and geothermal), which can generate electricity at or near maximum capacity for as long as necessary (except when experiencing an outage), exhibit high marginal ELCCs and are not subject to saturation. Differences in their relative ELCCs are primarily a function of outage rates.
- Variable resources (solar, wind), whose output varies from hour to hour as a function of uncontrollable meteorological conditions, exhibit low marginal ELCCs, reflecting the fact that during critical periods, their output is likely to be significantly lower than their full capacity. The marginal capacity value of solar in the Southwest, in particular, is very low (under 10%) due to the fact that critical periods occur during the evening.
- Energy-limited resources (storage, demand response), which have intrinsic finite limitations on the duration of their operations, exhibit high marginal ELCCs at low penetrations (when the system is capacity-constrained) but low marginal ELCCs at higher penetrations (when the system is energy-constrained). These saturation effects are observed across technologies: for instance, the significant increase in storage penetration from 2025 to 2035 drives a reduction in the marginal ELCC of both storage and demand response.

Table 4-5. Marginal ELCCs by technology in 2025 and 2035

Category	Technology	2025	2035	Change
Firm	Nuclear	94%	92%	-2%
	Coal	82%	-	-
	Natural Gas	91%	93%	+2%
	Geothermal	90%	88%	-2%
Variable	Solar	5%	7%	+2%
	Wind	26%	21%	-5%
Energy Limited	Hydro	73%	73%	-
	Battery	93%	36%	-57%
	DR	87%	38%	-49%

4.4.5. Sensitivity Analysis Results

Beyond understanding the reliability risk from the expected future regional portfolios, this study explores a range of potential risks to the region. These sensitivities on the regional resource adequacy risks tests the impact on the capacity position based on changes in resource performance, peak load uncertainty, and changes to the region's thermal portfolio composition.

The sensitivities are designed to capture emerging resource adequacy challenges facing the energy industry. Increasing frequency of extreme weather has led to increased forced outage risk to all resources and increased observed load. In addition, large load additions are accelerating the need for capacity and energy across the industry. Table 4-6 describes each sensitivity tested.

For resources, this study applies increased resource risks to the region's natural gas and storage resource fleet, two resources the region currently and will rely on to meet reliability risk. For storage, additional energy degradation sensitivities are applied. This study also studies the effect of low water availability under drought conditions for the region's hydro resources.

For load, the recent heatwaves in the Southwest 2023 and 2024 resulted in consecutive high load days. This sensitivity captures the increased frequency of extreme weather, testing the region's adequacy under the assumption that the 1-in-5 peak becomes the normal conditions. This study also focuses on the increased risk, but also capacity value, of data centers. This sensitivity looks at the risk associated with an accelerated timeline and the value of load flexibility.

A few themes emerge across the sensitivities:

1. Higher resource forced outage rates increases the risk to the region. By 2032, the natural gas fleet continues to serve as the region's main resource during the critical periods. Doubling the gas forced outage rate reduces the position by 968 effective MW in ELCC. Similar results

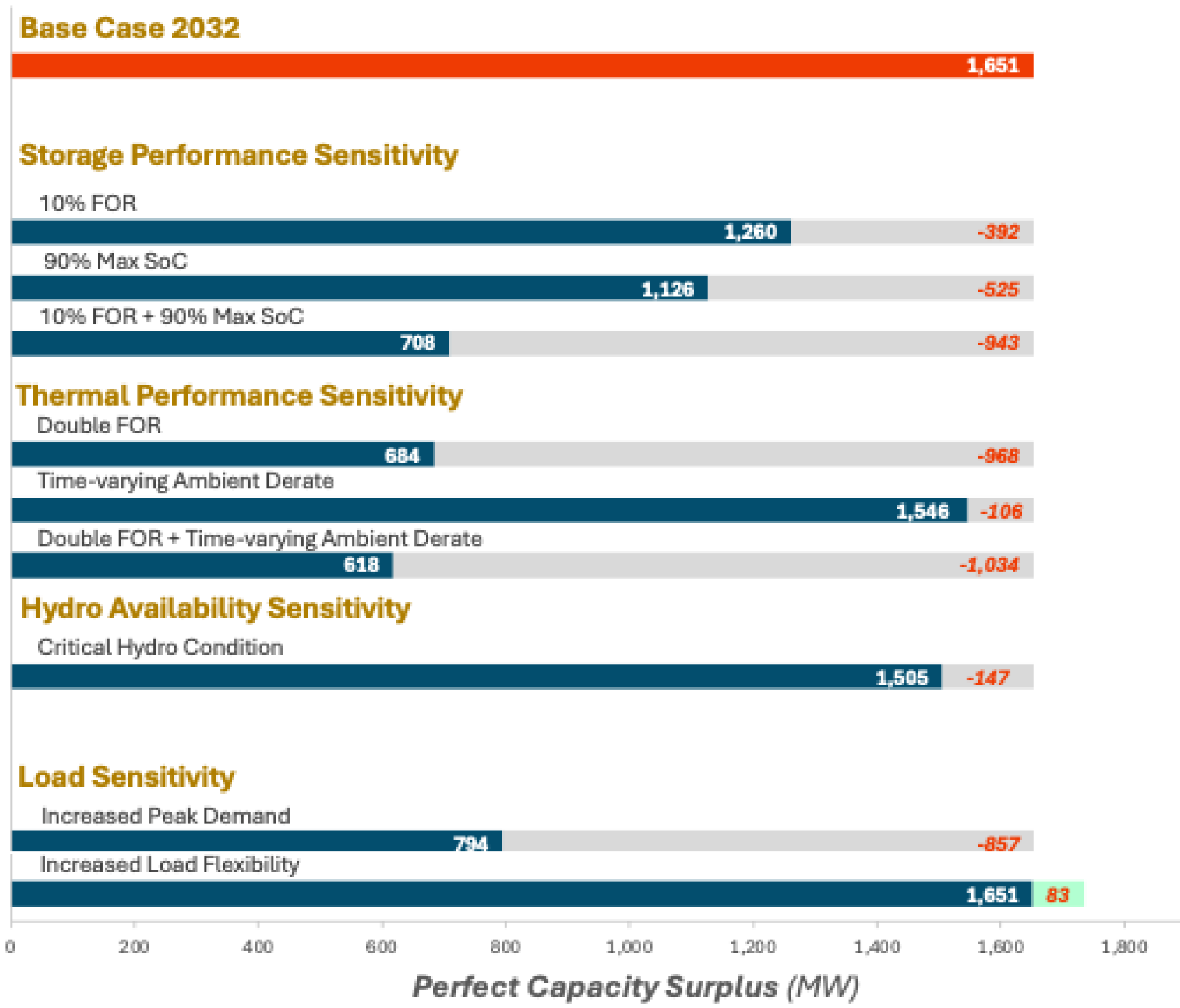
are observed for storage but compounds when the region's fleet increases in outage frequency and has 10% less energy, exacerbating the energy-deficiency problem.

2. Increased frequency of extreme weather (1-in-5 weather conditions) led to an increase in 857 MW higher capacity needs, equivalent to 2.4% of the median peak. Load flexibility can help mitigate some of increased load, but the impacts are lower than the incremental load added to the system.

Table 4-6. Range of 2032 Sensitivities

Category		Sensitivity Case	Description
Thermal Performance	A	Higher Gas Outages Rate	**Double all gas plants FOR** to reflect greater thermal stress from rising summer temperatures and more frequent winter cold weather disruptions
	B	Higher Ambient Derate	**Derate gas fleet summer rating by 5%** to reflect reduced output during long-lasting heat wave conditions
	C	Combine A & B	
Storage Performance	D	Higher Storage Outages	**Increase storage FOR assumptions from 5% to 10%** to account for potential battery performance degradation due to extreme temperatures
	E	Accelerated Battery Degradation	**Reduce storage maximum State-of-Charge from 100% to 90%** to reflect performance degradation due to capacity fading during extended heating events
	F	Combine D & E	
Hydro Availability	G	Critical Hydro Condition	**Assume critical drought conditions** to stress-test hydro energy availability
Load Requirements	H	Increased Median Peak	**Scale weather years so that median peak demand represents a 1-in-5 weather year** to reflect more challenging planning conditions
	I	Increased load flexibility	**Assume load components can achieve higher level of flexibility** during periods of grid stress

Figure 4-13. Achieved 2032 Capacity Position Across Various Sensitivities.



4.5. Discussion

The region faces a substantial and growing need for new capacity in the coming decade, and utilities' resource plans have identified portfolios capable of meeting that need. Regional coincident peak demand is projected to grow by roughly 30% over the next decade while assumed retirements remove nearly 8,000 MW of effective capacity from the existing portfolio. Taken together, the region's total need for new capacity grows to approximately 18,000 MW of new effective capacity by 2035.

Utilities' current plans, which include over 40,000 MW of new nameplate capacity, are projected to close this gap and maintain regional reliability at or better than the 0.1 days per year LOLE target, provided resources are brought online according to planned schedules.

The growing share of non-firm resources in the portfolio, projected to account for roughly half of total effective capacity by 2035, is shifting the timing of reliability risk away from the traditional afternoon peak and into the late evening and overnight hours. This effect is already observable today and is expected to intensify as storage penetration increases, with elevated overnight risk potentially emerging as soon as 2027.

This shift has direct implications for resource accreditation: marginal solar contributes relatively little to reliability at current penetration levels (5 to 7% ELCC), and the capacity value of 4-hour storage is projected to decline from approximately 90% in 2025 to 38% by 2035. These dynamics reinforce the continued importance of firm resources, which can generate on demand across extended periods when renewables and storage may be unavailable or depleted. Today, the viable options are limited and remains largely natural gas and nuclear.

Achieving the scale of development called for in utility plans will require adding over 4,000 MW of new capacity per year. The sensitivity analysis confirms that even modest delays in resource development or further upward load revisions could tighten the regional load-resource balance materially.

While the near-term assessment provides a focused evaluation of whether today's utility plans are sufficient to maintain reliability through 2035, it does not address the longer-term question of what features and characteristics of resource portfolios are able to meet long-term reliability needs. Section 5 builds on this foundation by examining a range of portfolios capable of meeting regional resource adequacy needs through 2045, exploring how the dynamics observed in the near term evolve at higher penetrations of renewables and storage and across a broader range of load, technology scenarios, and energy mixes.

5. Long-Term Resource Adequacy Assessment

5.1. Scope of Analysis

Whereas the near-term assessment focuses on the question of whether utilities' plans will maintain resource adequacy over the next ten years, the long-term assessment explores a broader question: what are the features and characteristics of resource portfolios capable of meeting long-term resource adequacy needs? Over a time span that extends beyond some utilities' planning horizon, key uncertainties impacting need are magnified, and the range of possible pathways to meet resource adequacy needs expands. Therefore, rather than focusing on evaluation of a single portfolio, the long-term assessment examines a range of potential portfolios. The long-term assessment utilizes a combination of **long-term capacity expansion (LTCE)** and **LOLP modeling** to design and evaluate twenty-three plausible portfolios that satisfy regional needs by 2045. Each portfolio is created based on a unique combination of the following three variables:

- **Demand Forecast:** three different levels of long-term load growth (Reference, Low, and High);
- **Technology Set:** four different options for the combinations of technologies available to meet incremental needs (Existing Technologies Only, Existing and Emerging Technologies, Existing and No New Gas, and Existing and Emerging, but No New Gas)
- **Clean Energy Penetration:** five different levels of energy mixes, defined using the penetration of clean energy ranging from 60% to 95%, measured based on the percentage of annual energy needs served by carbon free resources.[26]

The twenty-three combinations of these variables that are explored in this assessment are shown in Table 5-1. For each case, LTCE and LOLP models are used together to identify a least-cost portfolio of resources to meet regional resource adequacy needs, subject to specified requirements for the generation mix.

[26] The different clean energy penetrations are a key study design element and does not reflect the region nor any individual utility's goals. Changing the clean energy penetrations allows the study to explore common and uncommon patterns across a broader range of possible future portfolios and energy mixes.

Table 5-1. Twenty-three portfolios created and evaluated in for long-term assessment

Load Forecast	Technology Set	Clean Energy Penetration (% of Energy)				
		60%	70%	80%	90%	95%
Reference	**Existing**	●	●	●	●	●
Low	Existing	●	●	●	●	●
High	Existing	●	●	●	●	●
Reference	Existing & Emerging	●	●	●	●	●
Reference	Existing (No New Gas)					●
High	Existing & Emerging					●
High	Existing (No New Gas)					●

Each combination of these assumptions evaluated in this study is intended to represent a hypothetical long-term portfolio, rather than as a predictive or prescriptive outcome for the region. None of these portfolios are directly representative of current utility plans and no single portfolio developed herein is intended to reflect any sort of preferred or recommended regional resource plan, however all portfolios must achieve a target LOLE of 0.1. By doing so, the twenty-three portfolios studied – together, as a set – establish long-term ranges to bound the needs for specific types of resources; illuminate tradeoffs between different types of resources; and provide a basis for identifying common themes that are applicable across a wide range of potential outcomes.

5.2. Modeling Approach

The long-term assessment relies on a three-step modeling process to generate and evaluate future system portfolios and performance:

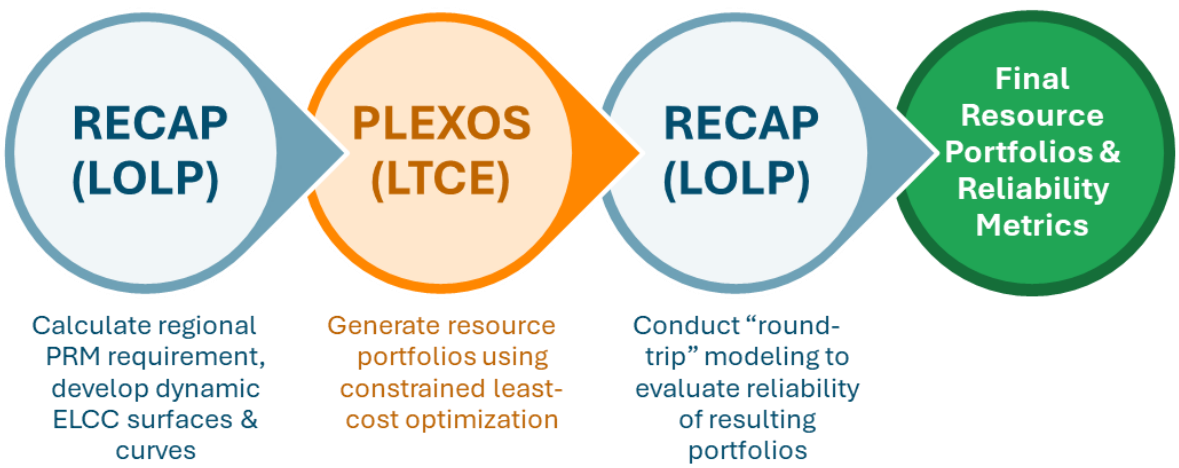
- First, a regional PRM requirement and ELCC curves for new resources are developed using RECAP to conduct LOLP analysis. This analysis builds directly on the datasets generated in the near-term analysis.
- Second, PLEXOS[27] is used to conduct long-term capacity expansion modeling for each of the scenarios defined above. The PRM requirement and ELCC curves derived in the prior step serve as direct inputs into the LTCE modeling, where they are used to define constraints that ensure that sufficient resources are developed to meet regional resource adequacy needs.

[27] More information about the PLEXOS LT model is available on the Energy Exemplar website (https://www.energyexemplar.com/plexos).

- Third, the resulting portfolios are provided back to RECAP, where "round-trip" resource adequacy analysis is conducted to ensure that the level of observed reliability of the portfolio does not deviate substantially from the specified target and to allow for a deeper inspection of the reliability risks present in each one.

This three-step process, illustrated in Figure 5-1, provides the most comprehensive framework through which to evaluate the resource adequacy and drivers of risk present in a portfolio.

Figure 5-1. Three-step modeling process to generate and evaluate portfolios to meet long-term resource adequacy needs

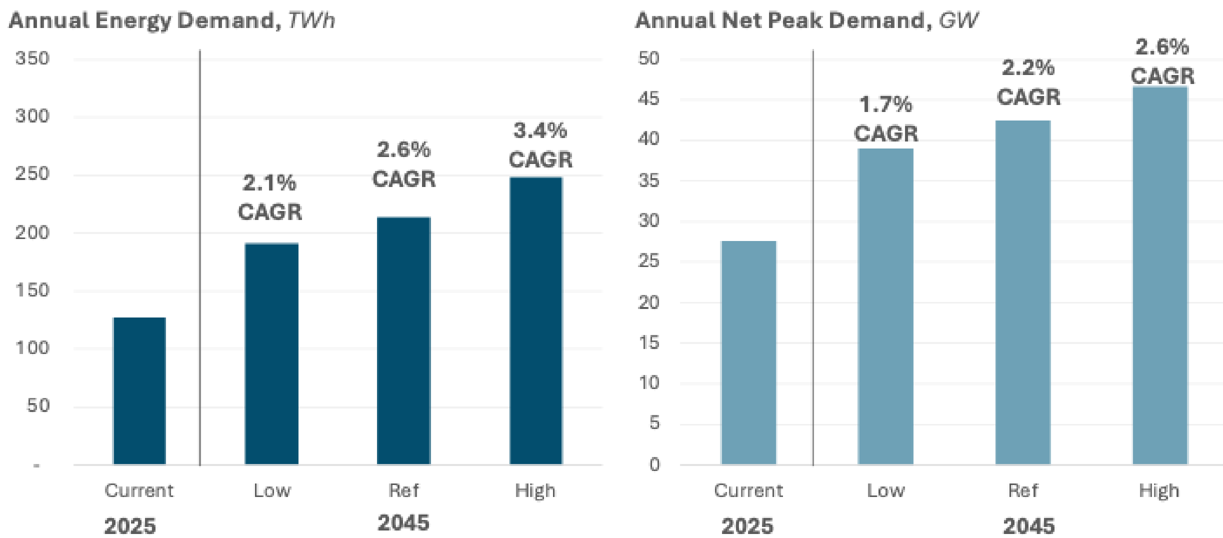


5.3. Key Assumptions

5.3.1. Long-Term Load Forecasts

This study explores the hypothetical portfolios across three load forecasts: Reference, Low, and High. The Reference load forecast represents a continuation of expected growth in the region across all the major load components. For each component, E3 used the 2030-2035 compound annual growth rate from the Phase 1 forecast as the Reference load growth expectation out to 2045. The Low load forecast represents a return to load growth seen earlier in the decade. For baseline and large load customer components, the growth is halved and the adoption of electric vehicles also slows down. The High load forecast represents continued base load growth and accelerated growth of electric vehicles and large loads. Figure 5-2 shows the 2025 annual energy demand and the 2045 coincident peak demand. While both energy and peak demands grow between 2025, the total net energy demand grows at a faster rate relative to net peak demand due to the increase in large loads. These loads are assumed to have a 90% load factor, higher than the existing load factor of around 50%.

Figure 5-2. Southwest 2045 Net Annual Energy (TWh) and Net Coincident Peak (GW)



Across each of the load forecast, continued adoption of energy efficiency and behind-the-meter solar are projected out based on observations from the near-term analysis. For demand response, this study assumes a 5% of peak penetration of demand response is present across each portfolio.

5.3.2. Existing Resource Portfolio

The long-term analysis builds upon the resource portfolio data provided by the utilities for the near-term assessment. The long-term assessment includes the resources identified in the "2035 Existing and New Resources in Development" portfolio, shown in Figure *4-8*, with select modifications:

- Additional planned retirements (roughly 2,000 MW of existing natural gas capacity) between 2035 and 2045 reduce the capacity of the existing natural gas resource portfolio;
- Existing capacity of solar and storage resources are reduced as existing contracts roll off between 2035 and 2045; and
- The Harquahala natural gas plant, currently under utility contract that will soon expire, is assumed to remain in service over the analysis horizon.

These resources are used to populate PLEXOS with an initial regional resource portfolio.

5.3.3. Resource Expansion Options

PLEXOS LT identifies new resources to meet growing loads in two snapshot years: 2035 and 2045. The candidate resources described hereafter represent the menu of new resource options available in PLEXOS. Resource options are classified as either (a) commercially available or (b) emerging technologies; the former are considered as options in all cases (except where expressly prohibited), while the latter are included as options only in 2045 under the "Emerging Technology" sensitivities. The resource options considered are listed in Table 5-2. Resource options available in PLEXOS.

Table 5-2. Resource options available in PLEXOS

Commercially Available (All Cases)	Emerging Technology (Select Cases)
Solar (Arizona & New Mexico options)	Generic Storage (8hr)
Wind (Arizona & New Mexico options)	Generic Storage (12hr)
Natural Gas Combined Cycle	Generic Storage (100hr)
Natural Gas Combustion Turbine	Nuclear Small Modular Reactor (SMR)
Lithium-Ion Battery (4hr)	Enhanced Geothermal System (EGS)

Resource costs were based on the National Renewable Energy Laboratory's Mid Annual Technology Baseline and adjusted to reflect geography and expected market conditions in 2035. Many of the key near-term market trends driving investment decisions in 2026 have a lesser role to play in 2035. Key modeling assumptions include the sunset of current federal tariff impacts by 2030, expiration of solar and wind tax credits before 2030 (in line with the July 2025 budget reconciliation bill), ineligibility of battery storage for investment tax credits due to foreign content-based eligibility restrictions in current federal policy, and short-term gas turbine scarcity premiums that are assumed to normalize by 2035. Emerging technology options are assumed to be available beyond 2040. The following table shows 2045 capital costs and levelized fixed costs (including capital, financing, and fixed O&M costs) for candidate resources.

Table 5-3. Southwest 2045 capital and levelized fixed cost assumption for candidate resources (nominal $)[28]

Technology	Classification	Overnight Capital Costs ($/kW)	Levelized Fixed Cost ($/kW-yr)
Solar	Commercial	$1,776	$140
Wind	Commercial	$2,811	$223
Gas - CT	Commercial	$3,523	$299
Gas - CCGT	Commercial	$4,032	$323
Li-ion Battery (4-hr)	Commercial	$2,506	$233
Nuclear Small Modular Reactor	Emerging	$13,161	$1,271
Enhanced Geothermal System	Emerging	$16,668	$1,739
LDES (8-hr)	Emerging	$4,321	$402
LDES (12-hr)	Emerging	$8,714	$989
LDES (100-hr)	Emerging	$8,506	$965

[28] Resource costs are based on E3's RECOST model and assumptions used specific to the Southwest. For more information on E3's RECOST methodology, please refer to E3 website

New candidate wind and solar generators are subject to additional costs to capture the cost of transmission required to deliver renewable generation to load areas. Wind and solar resources incur two transmission-related costs: a system-level transmission cost representing an increase in transmission headroom required for new generation and an interconnection cost reflecting the cost to connect each individual plant to the bulk electric system.

New gas CT and CCGT resources include both the capital cost for power generation and incremental gas transportation cost adder. The adder reflects the need to secure additional firm fuel deliverability. The adder assumes existing regional gas pipeline capacity is fully subscribed and that new gas resources would need to procure incremental firm transportation rights or equivalent pipeline capacity service. The adder excludes operational fuel costs, which are modeled separately in capacity expansion, and should not double count any transportation, basis, or delivery costs already embedded in fuel price assumptions.

5.3.1. Effective Load Carrying Capability (ELCC) Assumptions

This study uses the planning reserve margin (PRM) and effective load carrying capability (ELCC) methodology to measure the contribution of different types of resources to the total resource adequacy need. Using the RECAP LOLP model developed in the near-term assessment, the long-term assessment incorporates dynamic ELCC curves and surfaces for variable and energy-limited resources to account for their changing contributions as a function of penetration. The ELCC curves used in the long-term assessment reflect resource additions relative to the “Existing & Planned” portfolio and are derived by adapting the model used in the near-term assessment to reflect projected 2045 loads. Examples of the curves produced from this exercise that are input into PLEXOS are shown below, illustrating how:

- The capacity value of incremental wind resources begins at a moderate level (30%) but declines as the proportion of wind in the portfolio increases;
- The capacity value of additional storage resources begins relatively high (80+%) but declines as the system becomes increasingly energy constrained; and
- The rate at which storage capacity value declines depends upon the penetration of additional solar; because solar and storage resources complement one another, higher penetrations of solar slow the declining marginal ELCC of storage.

Figure 5-3: Incremental Wind Capacity Value and Incremental ELCC

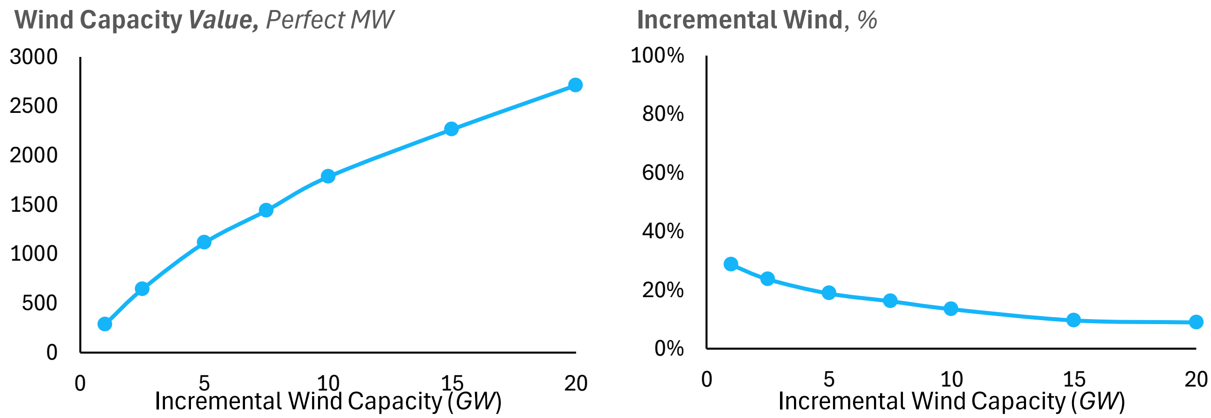
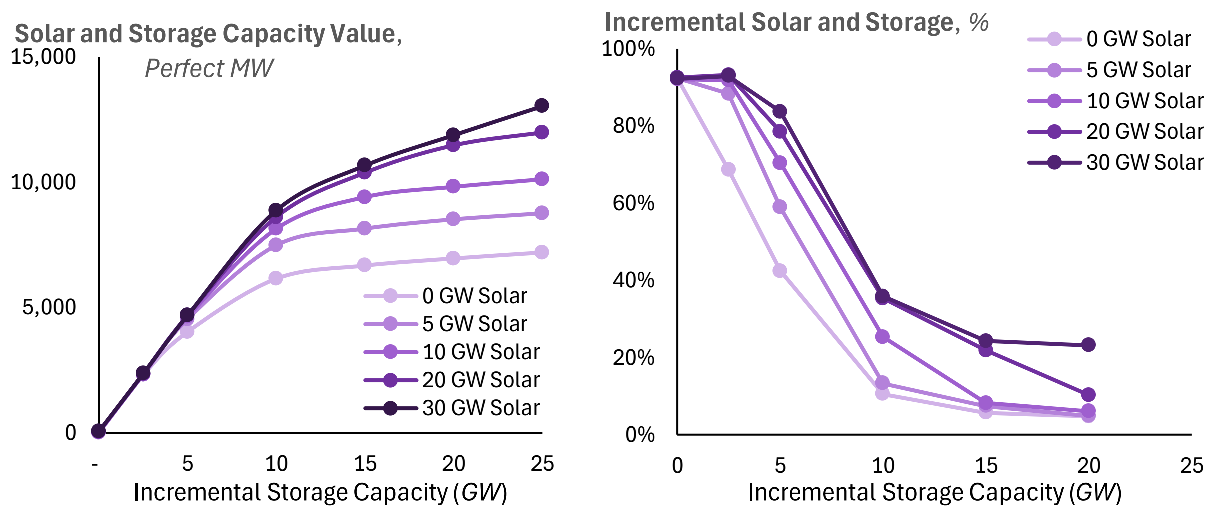


Figure 5-4: Incremental Solar and Storage Capacity Value and Incremental ELCC

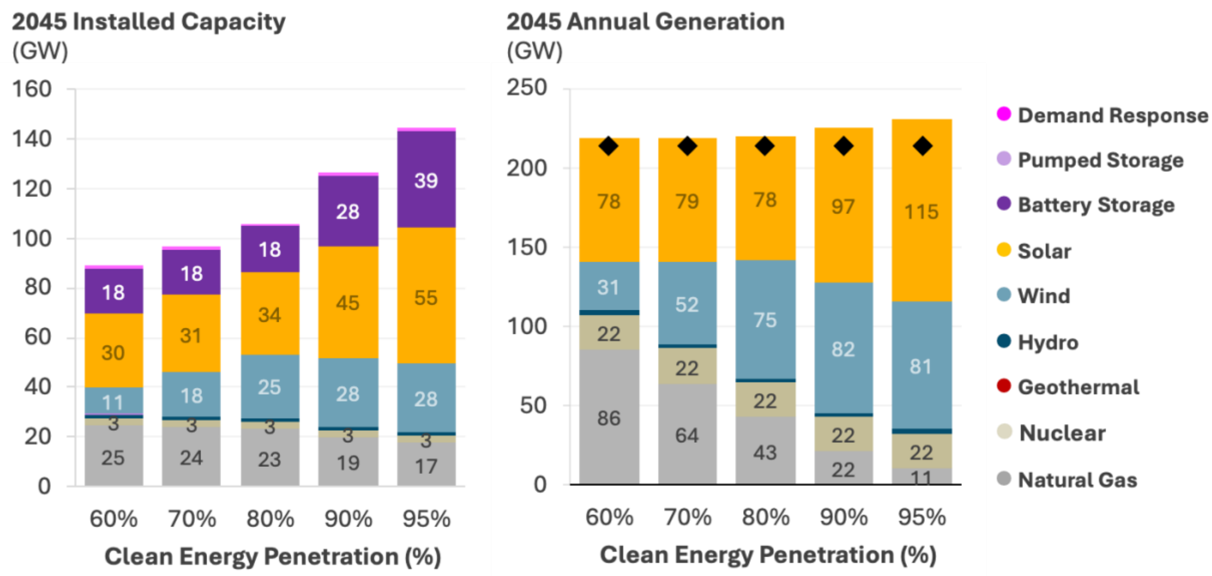


5.4. Results

5.4.1. Resource Portfolios

The installed capacity and annual generation by resource type for five portfolios spanning clean energy penetrations from 60 to 95% under the Reference load forecast are shown in Figure 5-5. This collection of portfolios, each designed to meet a regional resource adequacy target of 0.1 days per year, shows a range of plausible energy mixes while meeting long-term energy and resource adequacy needs in the Southwest region.

Figure 5-5. Installed capacity and annual generation mix at different clean energy penetrations, Reference load forecast



Several observations can be made across these portfolios:

- Of the five portfolios, four (60-90% Clean Energy) produce LOLE results that achieve or are below the 0.1 days per year LOLE target.
- While the specific quantities vary, all portfolios meet regional resource adequacy needs with a diverse mix of firm (gas and nuclear), renewable (wind and solar), and energy-limited (storage, DR, and hydro) resources.
- The differences in capacity among portfolios provides a measure of the relative effectiveness firm, variable, and energy-limited resources in contributing to resource adequacy needs: from 60 to 95%, the total quantity of incremental renewables (+42 GW) and storage (+21 GW) is nearly eight times greater than the quantity of natural gas resources displaced (-8 GW).
- While the share of the energy mix served by natural gas decreases in inverse proportion to the penetration of clean energy resources, the amount of installed capacity needed to maintain reliability does not exhibit the same decline. Even in a 95% clean energy portfolio where natural gas accounts for only 5% of annual energy, the installed capacity of natural gas resources (17 GW) is roughly 40% of the system peak demand.

More detailed reliability statistics for each of these portfolios are reported in Table 5-4.

Table 5-4. Reliability statistics for portfolios spanning 60 to 90% Clean Energy penetration

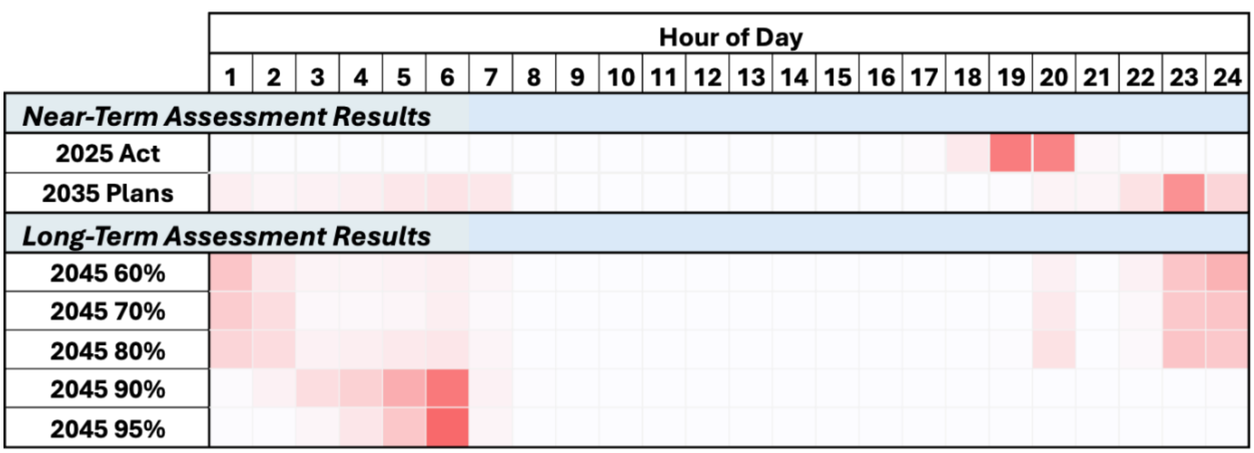
Portfolio	Loss of Load Expectation (days/yr)	Expected Unserved Energy (MWh)	Loss of Load Hours (hrs/yr)
60% Clean Energy	0.11	237	0.21
70% Clean Energy	0.11	220	0.19
80% Clean Energy	0.08	190	0.15
90% Clean Energy	0.07	158	0.15
95% Clean Energy	0.01	21	0.01

5.4.2. Drivers of Reliability Risk

Beyond 2035, the timing and nature of potential reliability risks will continue to evolve as a function of continuing changes to the resource mix. Figure 5-6 shows the timing of loss-of-load risk for each of the five portfolios discussed above (compared against results from the near-term assessment). This figure shows that:

- Because all long-term portfolios include a substantial quantity of solar and storage resources, all five experience loss-of-load risk in the evening and overnight periods.
- The risk profiles for the 60%, 70%, and 80% portfolios are similar in nature to the observed patterns in the utilities' 2035 plans: the periods of highest risk occur around midnight – when load not yet reached its overnight lows and storage resources begin to reach exhaustion – but also stretches into the early morning hours.
- In the 90% and 95% portfolios, the higher penetrations of storage resources cause risk to shift even further into the early morning period, and the timing of greatest risk can occur any time between sundown and sunrise – when load is beginning to increase but storage resources have not yet had a chance to recharge after discharging overnight.

Figure 5-6. Comparison of risk patterns observed in near- and long-term assessments



Across the range of portfolios, this study further investigates what types of factors are most likely to lead to these types of loss-of-load events in each portfolio, focusing on four main potential drivers:

1. High load, extreme summer days,
2. Coincident thermal forced outage conditions
3. Consecutive moderate or below average solar output days,
4. Insufficient stored energy in energy-limited resource fleet.

While all futures experience some form of these drivers, emphasis is different depending on the portfolio composition. Optimized portfolios with higher thermal capacity are more capable of covering high load, non-solar periods, provided expected performance from each power plant. Meeting nighttime reliability will increasingly depend on the availability individual units, something Southwest utilities are acutely aware of today. However, other resources must also perform well during these same periods

While high solar availability and output tend to correlate with high load days, even a few days of average or below-average solar performance ahead of heatwaves results in energy deficiencies in 2045. In all futures observed, solar installed capacity penetration is 75% of peak or higher, effectively meeting midday demand across all futures. However, consecutive days of low solar output reduce the effectiveness of other resources that rely on its energy, namely charging storage and deferring output until nighttime.

By 2045, storage, hydro, and on rare occasions, demand response, is dispatched during nighttime hours, provided it has sufficient energy available. If the preceding hours have ample solar generation, storage and hydro output can be delayed until after sunset. If the preceding hours have below-average solar output, the residual demand increases the pressure for the dispatchable resources to fill the void. During rare days of high load combined with lower-than-normal solar availability, reliability outcomes are primarily driven by lower solar availability.

5.4.3. Relative Portfolio Costs

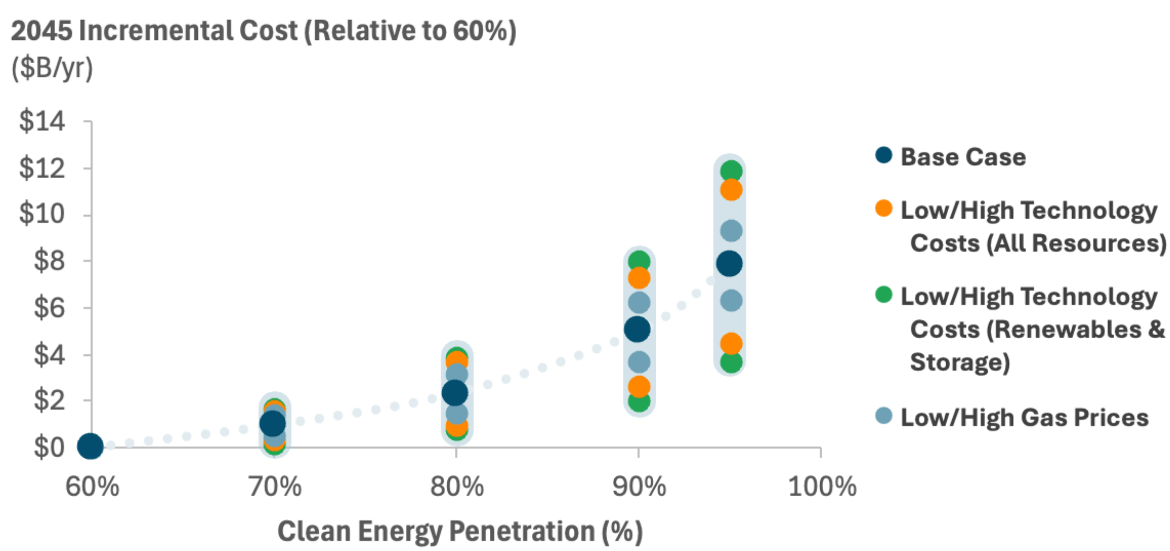
While cost is not a primary focus of this assessment, capacity expansion modeling provides useful directional information on the relative costs of different portfolios since it identifies least-cost resource portfolios subject to the specified constraints. Because the major drivers of scenario costs – the physical costs of the resources, supporting transmission infrastructure, and the fuel costs to operate them – are all highly uncertain across a twenty-year planning horizon, relative costs among the scenarios are shown for five sets of assumptions:

- Using E3’s “Base Case” cost trajectories for resource, fuel, and transmission costs, which were the basis of the least-cost optimization in PLEXOS;
- Under alternative “high” and “low” technology cost assumptions (+/-20% relative to mid), applied to all resource and transmission investments;
- Under alternative “high” and “low” technology cost assumptions (+/-20%), applied only to renewable and storage resources; and
- Under alternative “high” and “low” natural gas price forecasts (+/-50%).

The sensitivities on resource, transmission, and fuel costs are inherently generic by design, intended to illustrate the relative relationships among the different contributing factors to portfolio costs. The resulting ranges of portfolio costs, measured relative to the 60% Clean Energy portfolio, are shown in Figure 5-7. These results inform three useful insights:

- Under “Base Case” cost assumptions, portfolios with higher clean energy penetrations have higher costs than portfolios with lower clean energy penetration.
- The costs of increasing clean energy penetration grow at an increasing rate (reflected by the exponential shape of the curves), a reflection of the declining value of renewables and energy storage at higher penetrations.
- Under certain alternative sensitivities (low renewables & storage costs, high natural gas prices), the costs observed in the 70% and 80% Clean Energy portfolios are not materially higher than the 60% Clean Energy portfolio, indicating that economic fundamentals alone may be one factor that could lead utilities to portfolios with higher clean energy penetrations.

Figure 5-7. 2045 incremental system costs, compared to 60% Clean Energy portfolio (nominal $)



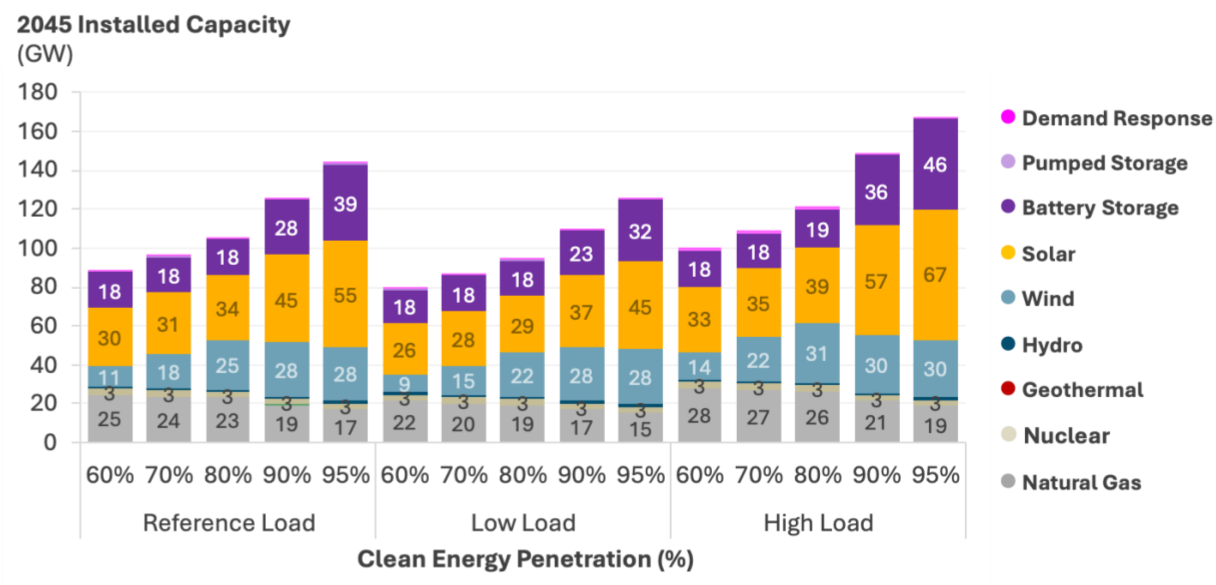
5.4.4. *Portfolio Sensitivity Analysis*

5.4.4.1. *Load Forecast Sensitivities*

To explore how load forecast uncertainty impacts the long-term regional resource needs for resource adequacy, additional sets of portfolios are created under alternative Low and High load forecasts. Figure 5-8 compares the resulting ranges of portfolios (which also span clean energy penetrations from 60 to 95%) against the results in the Reference load forecast. While the magnitude of total resource needs to ensure reliability differs across load forecasts, the resulting portfolios are similar in more ways than they are different:

- All portfolios require significant additions of new generation infrastructure relative to today's system. Even the portfolio with the lowest total quantity of resources (60% clean, low load forecast) requires roughly 50 GW of new installed capacity, more than the total capacity of the existing system today.
- All portfolios meet reliability needs with a complementary blend of firm, variable, and energy storage resources.
- All portfolios include new natural gas additions to meet a portion of long-term resource adequacy needs, and fourteen of the fifteen portfolios include gas additions beyond the resources currently under development (the lone exception is the 95% Clean Energy, Low Load portfolio).

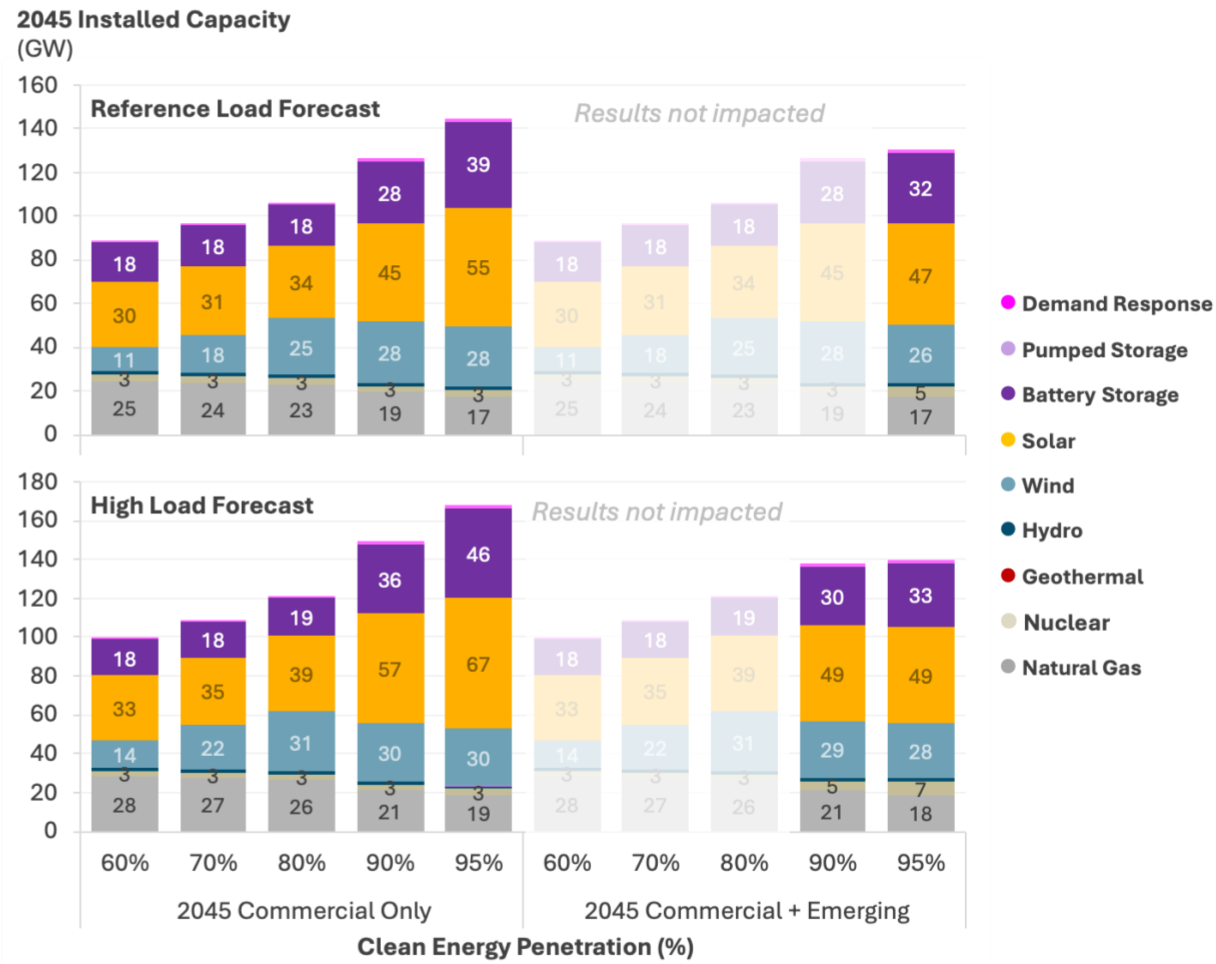
Figure 5-8. Installed capacity by technology under Low, Reference, and High load forecasts



5.4.4.2. *Emerging Technology Sensitivities*

The Reference and High Load cases are modeled with under a sensitivity where emerging technologies described in Section 5.3.3 are available for selection in 2045; these results highlight the potential value of additional resource options. Figure 5-9 compares the installed capacity of portfolios with commercial resources only to their counterparts where emerging technologies are allowed for the Reference Load forecast (top) and High Load forecast (bottom). While no emerging technology options are selected at the lower clean energy penetrations, new nuclear resources are selected at the 90% (High Load only) and 95% (Reference and High Load) levels. Notably, in both cases, the new nuclear resources primarily displace other clean resources (wind, solar, and storage) instead of natural gas.

Figure 5-9. Southwest 2045 Total Installed Capacity (GW) | Reference Emerging Case



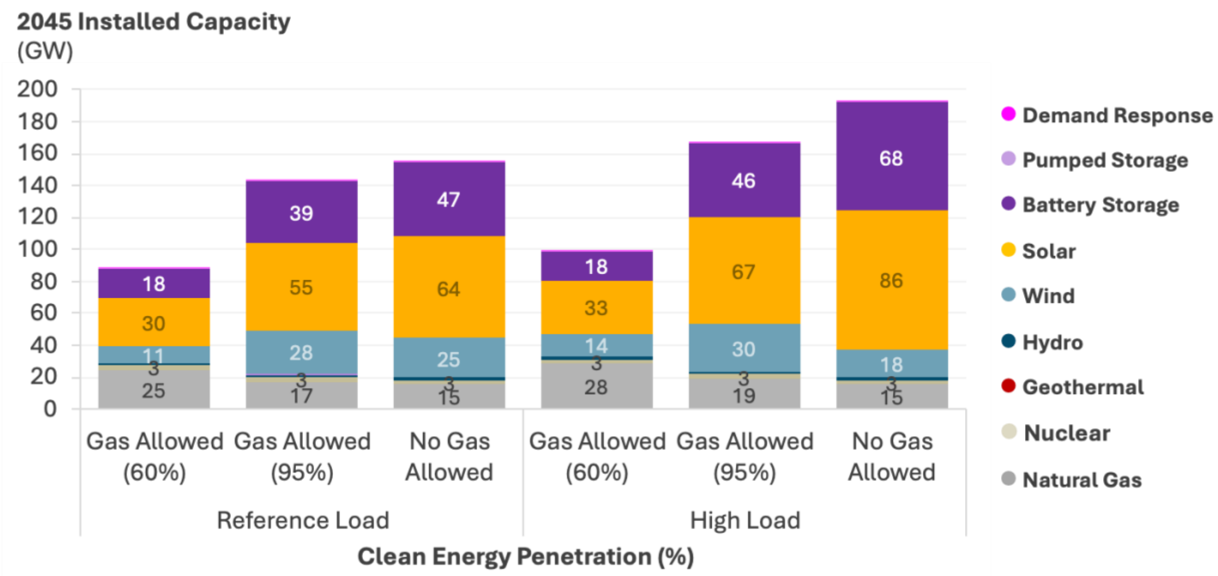
These results depend upon the cost input assumptions used for emerging technologies, and while the cost assumptions used in this study are intended to be reflective of emerging technologies reaching broad market readiness, technological breakthroughs could result in even larger quantities of emerging technologies providing viable options to contribute to regional resource adequacy needs.

5.4.4.3. No New Natural Gas Sensitivity

To further examine the role of firm resources, this study also investigated scenarios in which the new natural gas resources were not included as an option in the LTCE modeling. Figure 5-10 shows total installed capacity in the 95% clean energy portfolios of the reference and high load cases with and without this constraint to new gas builds. The constraint to new gas builds results in a larger system size.

- In the Reference Load case, avoiding the 2 GW of new gas capacity selected in the 95% Clean Energy portfolio requires an additional 8 GW of storage and 6 GW of renewables.
- In the High Load case, avoiding the 4 GW of new gas capacity selected in the 95% Clean Energy portfolio requires an additional 18 GW of storage and 11 GW of renewables.

Figure 5-10. Installed capacity comparison between portfolios with and without new natural gas considered as an option



Under the no new gas allowed cases, loss-of-load events are larger in magnitude as a the result of energy deficiency. These are typically observed during sustained periods of low renewable production that may last multiple days and occur in the summer or the winter. Portfolios that include new gas resources successfully minimize this risk, as the quantity of firm resources capable of generating round the clock is typically sufficient to backfill the energy shortfalls from renewables; portfolios without new gas resources do not have sufficient firm resource capacity to meet system needs during these events, and the resulting effect is that a significant portion of load cannot be served over an extended period of time.

Figure 5-11 and Figure 5-12 provide contrasting examples of how portfolios with and without new gas resources perform under such an event (based on actual winter weather conditions observed from December 1 to 7, 2011). During this week, the Southwest region experienced a winter storm and cloudy conditions, resulting in abnormally low solar output on multiple cloudy days.

- In a portfolio with new natural gas capacity, the quantity of firm resources available (roughly 20 GW) is sufficient, in combination with lower outputs from renewables and storage, to maintain reliability through this event.
- In a portfolio without new natural gas capacity, storage resources are fully depleted on the second day, and because the amount of firm capacity available is much lower, the system experiences a loss of load event that spans from late evening on the fourth day to sunrise the next morning. Also notable about this event is its size: during the period of loss of load, roughly 10 GW – approximately one third of the region's loads – cannot be met by the resources in the portfolio.

Figure 5-11. Hourly Generation 95% High Load Case with Incremental Natural Gas, December 1-7 (GWh)

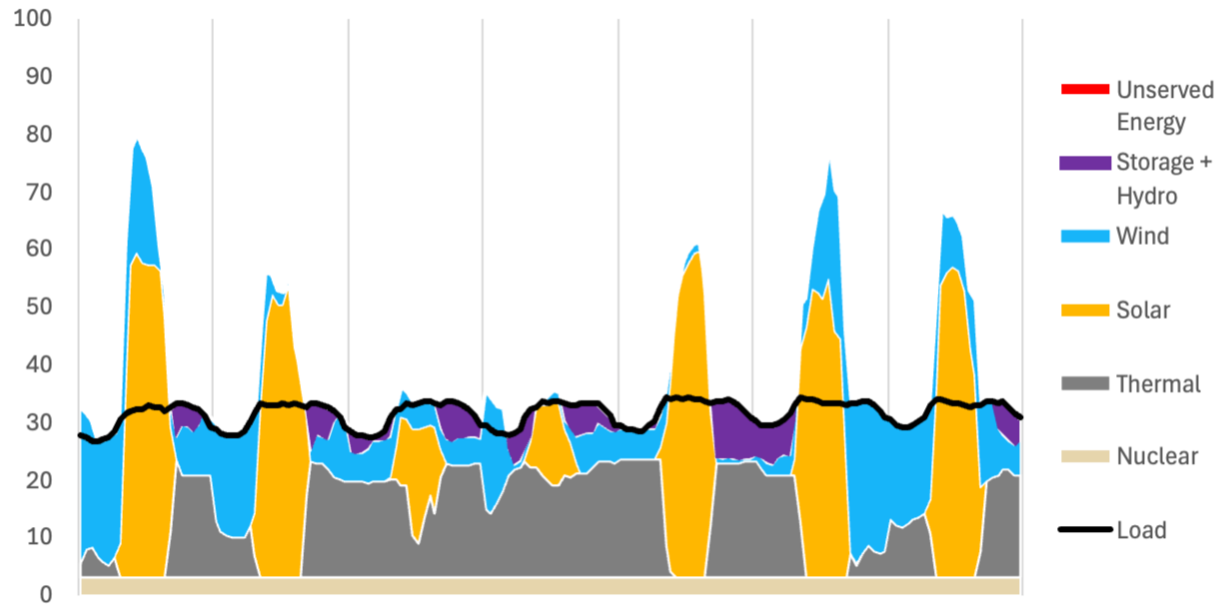
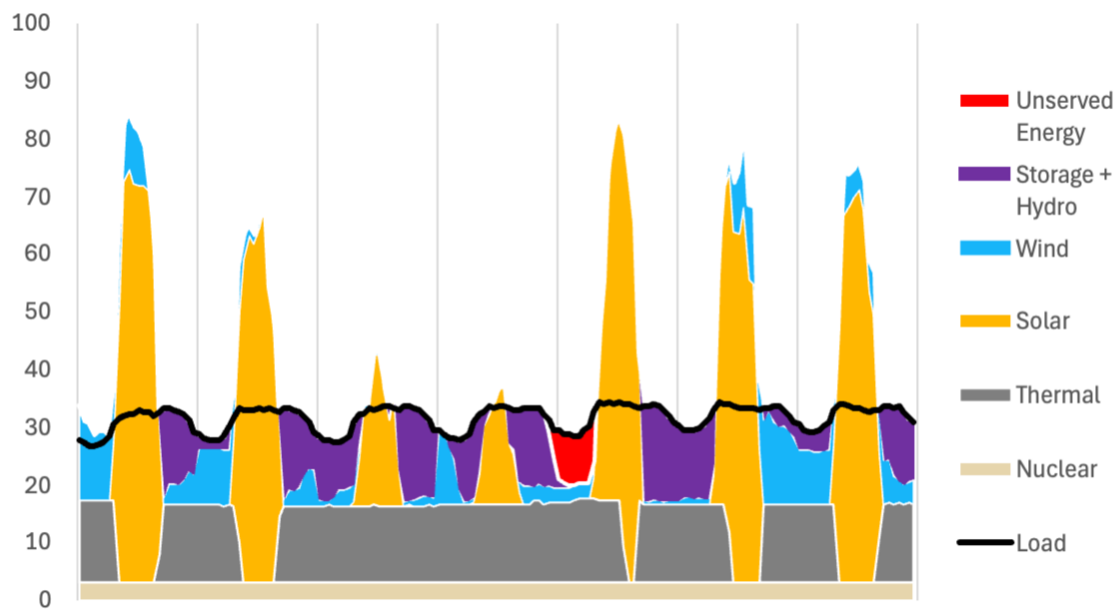
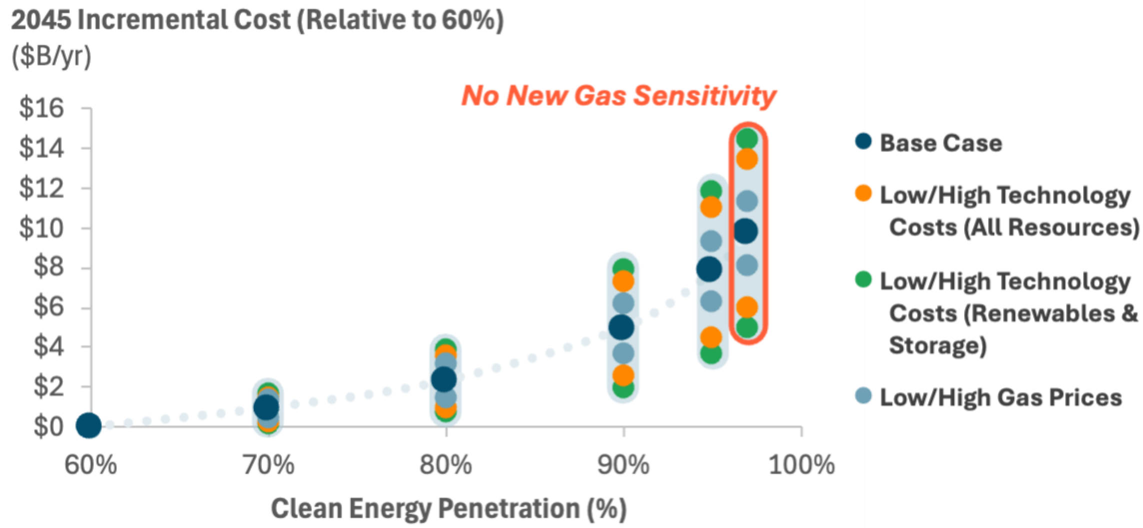


Figure 5-12. Hourly Generation 95% High Load Case Without Incremental Natural Gas, December 1-7 (GWh)



In addition to greater exposure to higher risks of large loss-of-load risks, portfolios that exclude new natural gas resources as an option also exhibit higher costs. Figure 5-13 compares the incremental costs associated with the "No New Gas" sensitivities against the suite of portfolios generated at different levels of clean energy penetration; across all cost assumptions, the sensitivity portfolio without gas shows higher costs than all alternatives, including the 95% Clean Energy portfolio.

Figure 5-13. Portfolio cost comparison including No New Gas sensitivity portfolio



5.5. Discussion

Across all long-term portfolios, maintaining resource adequacy requires a diverse mix of variable, energy-limited, and firm resources. Variable renewables (primarily solar and wind) provide large shares of annual energy, while energy-limited resources (storage, hydro, and demand response) shift energy across hours and help move periods with excess energy to periods with a deficit in energy. However, as penetrations rise, both variable and energy-limited resources experience declining marginal capacity value, reinforcing the need for portfolios that combine complementary resource types rather than relying on any single technology type.

Firm resources are critical to reliability in every portfolio because they can sustain output during multi-hour and multi-day periods when renewable production is low and energy-limited resources are depleted. In practice, this includes conventional firm capacity, such as natural gas (and existing nuclear), which serves as a backstop for critical periods across both summer high load periods and winter low-renewable conditions. The results show that even under higher clean energy penetration, portfolios add new firm capacity for limited periods when the system is capacity- and energy-deficient.

Today, the range of scalable firm options is limited, and natural gas remains the most viable broadly available choice to provide new firm capacity over the planning horizon evaluated in this assessment. Looking forward, if clean firm technologies become commercially available at scale, they can provide the same reliability role as conventional firm resources. In that future, clean firm resources could be dispatched to complement variable and energy-limited resources—providing sustained energy during low-renewable periods and preserving storage energy for the highest-risk hours—alongside any remaining conventional firm capacity.

6. Key Findings & Implications

6.1. Key Findings

The near-term and long-term assessments inform six key findings from this assessment. The first three focus primarily upon the results of the near-term assessment, and the second three build upon these based on the results of the long-term assessment.

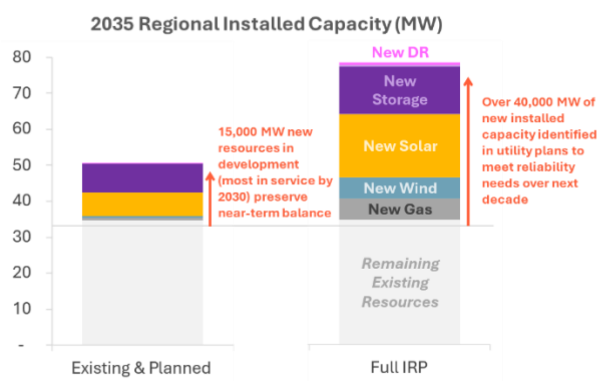
1. Need for New Resources is Urgent

Large increases in regional demand, coupled with anticipated retirements, continue to drive a significant need for new resources across the region to maintain reliability

Over the next decade, the anticipated demand based on utility inputs to this study shows regional coincident peak demand increasing from roughly 27,500 MW to over 36,000 MW. At the same time, assumed retirements and expiring contracts with existing resources result in the loss of nearly 8,000 MW of effective capacity from the 2025 existing portfolio. For a system at or near load-resource balance today, the compound effect of these two changes is a total need for new *effective* capacity of roughly 18,000 MW over the next decade.

2. Utility Plans Demonstrate Adequacy

Over the next decade, utilities' resource plans include new natural gas, renewables, and storage sufficient to maintain regional resource adequacy



Collectively, the utilities' resource plans provided as inputs for this assessment include over 40,000 MW of new installed capacity by 2035. If these resources are successfully brought in service according to prescribed schedules – which will require a rate of new resource additions far greater than recent historical trends – this study shows that the region will maintain sufficient generating capacity to ensure a level of resource adequacy consistent of LOLE of 0.1 days per year or better. Notably, the *nameplate* capacity of the resource additions included in utility plans (40,000 MW) far exceeds the amount of *effective* capacity they provide to the system to ensure reliability due to the inherent limitations of variable and energy-limited resources. [29]

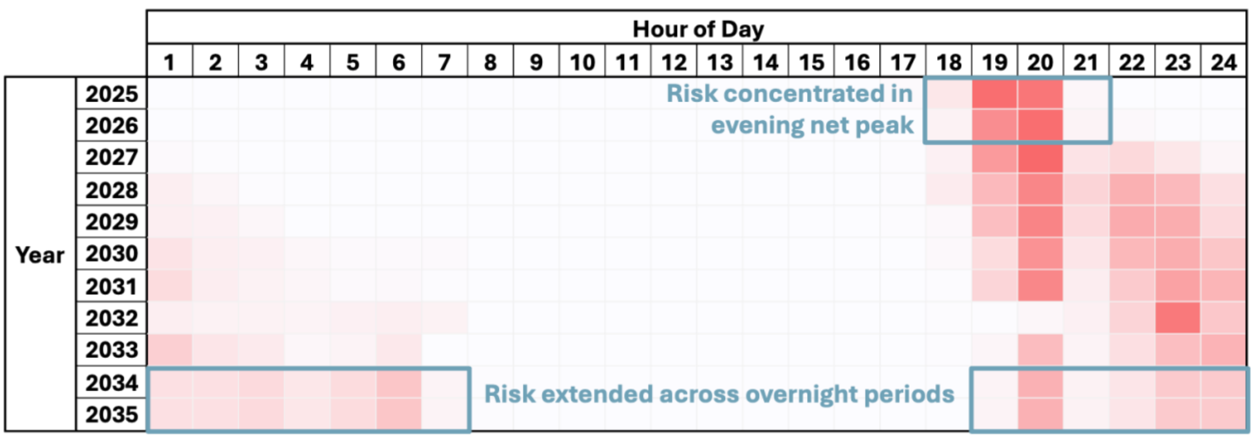
[29] Effective capacity (or perfect capacity) measures a resource's contribution to resource adequacy, typically measured against a "perfect resource" or a resource that is available at all times.

3. Reliability Risks are Shifting Rapidly

Reliability risk has already shifted from afternoon peak to the evening "net peak," and will extend deeper into overnight periods as resource mix evolves

The Southwest utilities are planning to meet a growing share of future resource adequacy needs with renewable and energy storage resources; by 2035, these resources are projected to account for roughly half of the total effective capacity in the region. These portfolio changes directly impact the timing of reliability risks, which shift away from the traditional peak period as penetrations of variable resources rise. This effect is already present in today's system, as the growth of solar has caused risk to shift into the evening. Over the next decade, increasing levels of energy-limited resources will continue to shift and extend the periods when the system is at the edge of reliability (see Figure 6-1). Based on utility plans, higher risks in the late evening and overnight periods could begin to emerge as soon as 2027.

Figure 6-1. Relative loss-of-load risk by time of day based on utility plans, 2025-2035



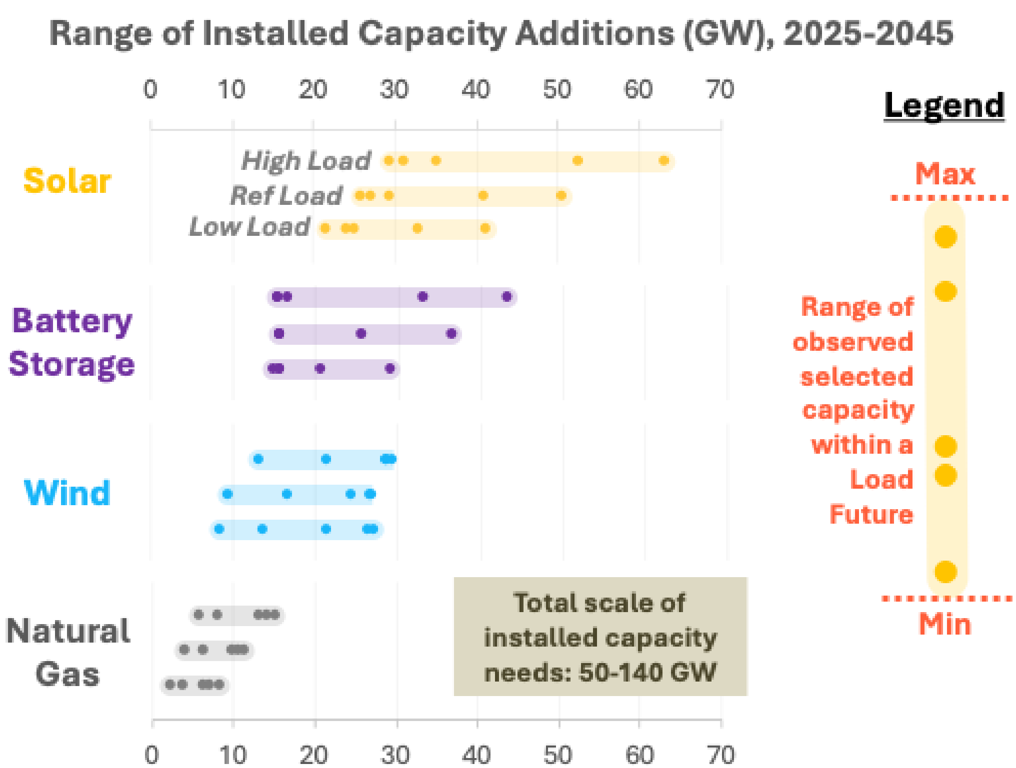
These effects are caused by evolving portfolio identified across all utilities to meet their needs, and in turn, directly impact the contributions that additional resources can make to resource adequacy in multiple ways. With existing solar penetration shifting risk to late evenings, marginal solar additions provided limited reliability value (marginal solar provides between 5 to 7%). Beyond 2027, the extension of risk into the overnight periods contributes to the observed declines in the marginal capacity value of short-duration storage resources (4-hr storage decreases from 90% in 2025 to 38% in 2035), which in turn increases the relative value of resources that can provide longer duration services to the grid and firm resources capable of generating over sustained periods without limits on their use.

4. Diversity is a Robust Long-Term Strategy

Meeting growth with a combination of new gas, renewables, and storage resources is a robust strategy across a wide range of longer-term future conditions

Beyond 2035, maintaining resource adequacy, as loads continue to grow and existing resources retire, will require substantial investments in new resources. This study demonstrates that regional resource adequacy can be met with a wide range of resource mixes, showing reliable resource portfolios that span from 60 to 95% clean energy; across all portfolios studied, the total amount of new installed capacity added between 2025 and 2045 ranges from 50 to 140 GW. In all cases where the availability of commercially available technologies is not explicitly restricted, long-term needs are met by a diverse mix of new renewables, storage and natural gas resources; the range of new resource additions by technology across the twenty-year period are shown in Figure 1-5. To the extent emerging technologies mature, they may also contribute to regional resource adequacy needs (as evidenced by the selection of new nuclear in several portfolios) but do not appear to diminish the importance of resource diversity. All portfolios also include continued expansion of energy efficiency and demand response; beyond these levels, additional demand-side resources (including behind-the-meter generation, virtual power plants, and incremental energy efficiency and demand response) could also contribute to meeting regional needs if they provide capabilities aligned with the future needs of the electricity system.

Figure 6-2. New installed capacity additions from 2025 to 2045 across portfolios in the long-term assessment

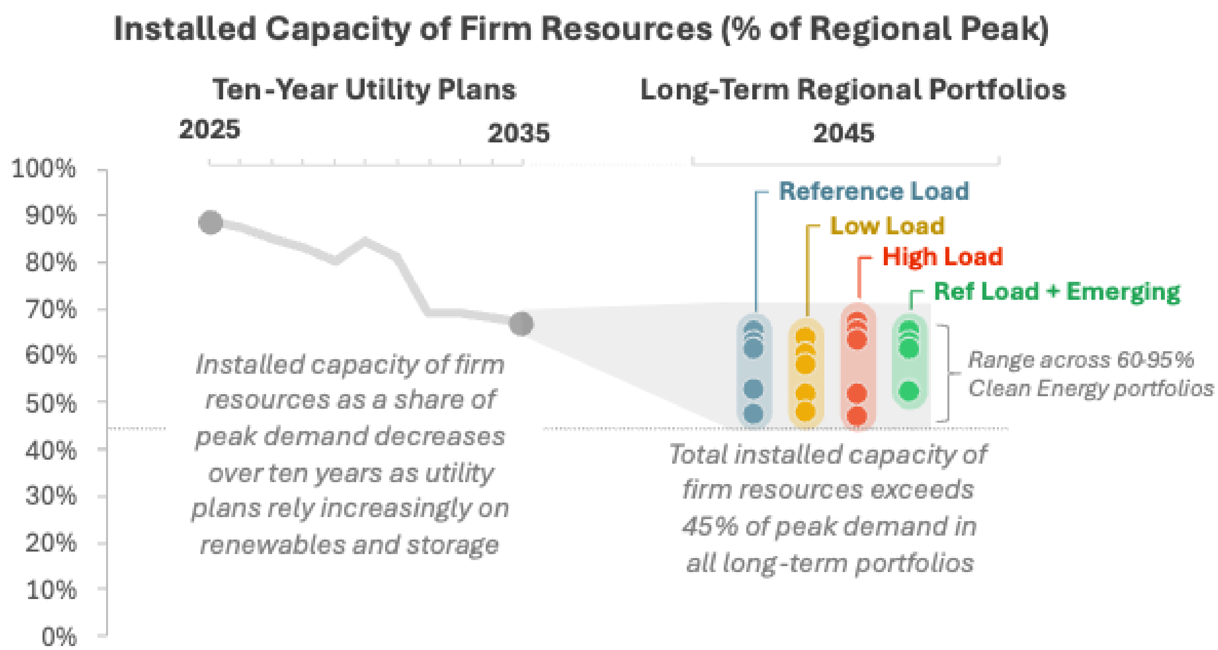


5. Firm Resources are Critical to Reliability

Firm generation resources remain essential to ensuring long-term resource adequacy and mitigating risks of large energy deficiencies, particularly during periods when renewable output is low

While the contributions of variable and energy-limited resources to resource adequacy are substantial across all portfolios analyzed, both categories of resources are subject to significant declines in their marginal capacity value at higher penetration. In practice, this means that even if portfolios include renewables and storage capable of serving most annual energy needs, ensuring resource adequacy also requires "firm" resources capable of producing energy across sustained periods when renewables and energy storage may be unavailable. Across all portfolios analyzed in the long-term assessment where new firm resource options are unconstrained, their total installed capacity ranges between 45-70% of system peak demand (Figure 6-3). In all long-term portfolios, nuclear and natural gas resources play a critical role in ensuring reliability when electric demand is high, renewable availability is low, and energy storage resources have been depleted (for instance, during cloudy winter weeks). Under such conditions, resources with the capability to generate on demand for as long as necessary allow the system to maintain reliability.

Figure 6-3. Summary of firm resource contributions across near-term and long-term assessments

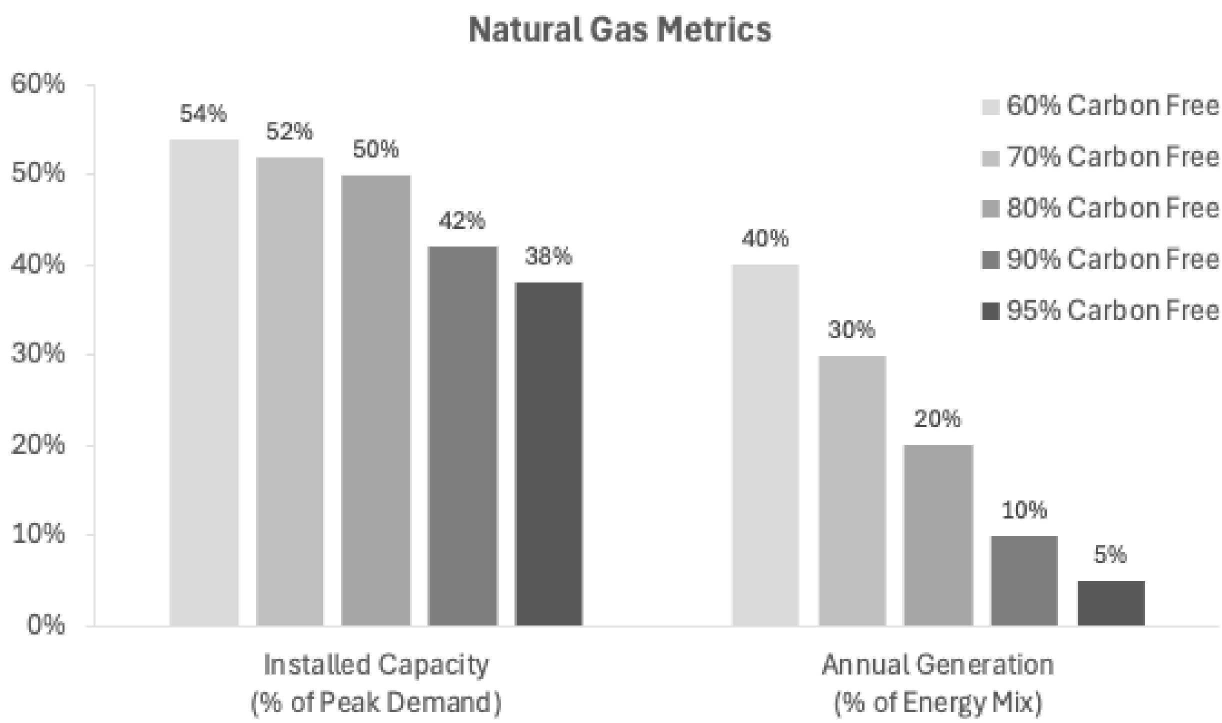


6. Natural Gas Remains the Primary Firm Option

Across all portfolios, natural gas fulfills the majority of the region's long-term need for firm resources, even under the highest clean energy penetrations studied.

The range of portfolios in the long-term assessment yields useful insights into the future adequacy of natural gas, captured through three metrics, shown in Figure 6-4: (1) **installed capacity,** the total gas capacity needed to ensure reliability and (2) **annual generation,** the share of regional energy produced by gas-fired resources. Across the portfolios, as clean energy penetration rises from 60 to 95%, annual gas generation falls sharply (from 40% to 5% of total energy) while installed capacity declines only modestly, from 54 to 38% of peak demand. This contrast is the key finding: increasing clean energy primarily reduces how often gas resources must run, not how much capacity is required. Even at 95% clean energy, a large amount of natural gas capacity (nearly 40% of peak demand) plays a critical reliability role, where it serves as a rarely-used backstop option during periods of low renewable output.

Figure 6-4. Key metrics for natural gas fleet in long-term adequacy assessment



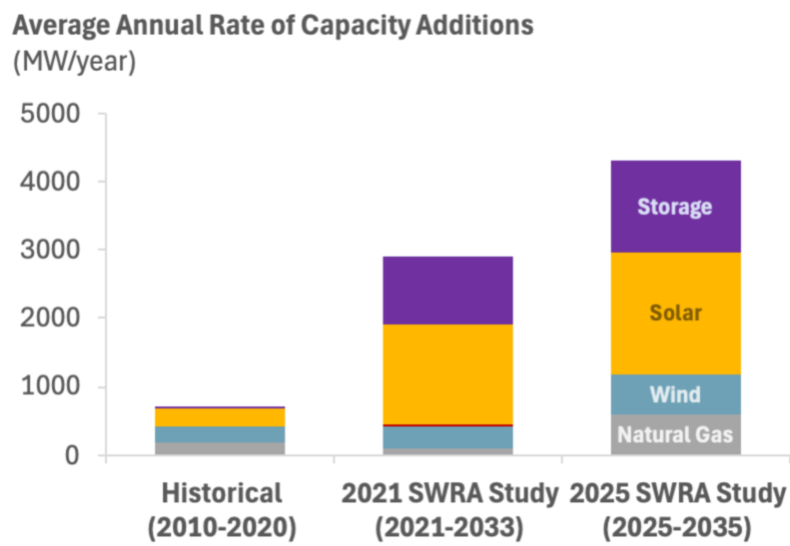
These results further underscore the finding that additions of new natural gas resources to the region are part of a robust strategy to meet near- and long-term resource adequacy needs, capable of supporting grid reliability across a wide range of future clean energy penetrations and load levels.

6.2. Conclusion and Implications

Both the 2021 and 2025 assessments indicate that, despite increasing portfolio complexity and evolving resource adequacy risks, the utilities' collective planning practices are effective in their identification of resource portfolios with the technical ability to maintain regional resource adequacy. Notably, the two assessments reached this conclusion while evaluating different load forecasts and resource portfolios. The consistency of this technical result provides strong evidence that utilities' methods and analytical toolkits provide a sound foundation for resource adequacy planning, and that utilities have used this foundation to adjust plans quickly in response to the changing outlook for future demand.

Having demonstrated that the utilities' plans have the technical capability to meet projected needs, the most immediate challenge for maintaining regional resource adequacy lies in successful implementation. Meeting the needs forecasted in this study would require that utilities add over 4,000 MW of new installed capacity to the system each year over the next decade – a quantity that exceeds the necessary rate of additions previously identified in the 2021 study and eclipses the long-term historical average by a factor of four (see Figure 6-5).

Figure 6-5. Comparison of annual average capacity additions



In an environment marked by heightened uncertainty and rapid change, translating these plans into reliable real-world outcomes presents a more multifaceted set of challenges than the planning itself. Successful implementation will require coordinated orchestration across a range of processes, systems, and institutions involving a wide range of regional stakeholders. The region's utilities will naturally play a central role in each step of implementation, but the ultimate outcomes will reflect the collective performance of actors and systems that no single entity controls. Given the rapid pace of change and potential for unanticipated shifts in the energy landscape, even well-formulated plans will likely require frequent reevaluation and revision; the ability to monitor emerging conditions, identify gaps early, and adapt accordingly will be as important as the plans themselves. The following risk factors represent the most significant aspects of implementation required to ensure resource adequacy:

- **Management of load forecast uncertainty:** since the 2021 study, utilities in the Southwest – and across the country – have experienced large increases in service requests from large customers, but the long-term growth of this new continues to be a major source of uncertainty. Ongoing revisions to load forecasts as the outlook for large customers evolves makes reliability planning a moving target and increases the risk of misalignment between resource development and actual system needs.

- **Procurement & supply chain:** since 2021, global and domestic supply chain constraints have contributed to an increasing trend of increasing project costs and longer lead times for key equipment, highlighting the potential for macroeconomic shocks to create perturbations with far-reaching impacts upon electric utilities. These dynamics are anticipated to persist as demand growth from data centers and other large customers continues at a national scale. This trend has led to an increasing number of project delays and cancellations in recent years and continues to lengthen development timelines for new resources. Longer lead times for new resources and higher risks of potential delays or cancellations will place pressure on utilities to accelerate procurement processes; with many new projects requiring up to five years to complete development, a large portion of the resource procurement to meet 2035 resource requirements will likely occur by 2030.
- **Transmission interconnection & deliverability:** in addition to planning a portfolio of resources capable of supplying load, utilities must also ensure that the transmission system is sized appropriately to allow those resources to be delivered to load when needed. Each new resource requires interconnection studies to identify necessary system upgrades, and large-scale resource development will likely necessitate major transmission expansions. These projects can take a decade or more to plan, permit, and construct. Proactive transmission planning, along with strategies to maximize the use of existing infrastructure as legacy resources retire, can help mitigate these risks.
- **Permitting & regulatory approval processes:** utilities and developers must obtain a variety of permits and regulatory approvals in the process of developing new generation (and associated transmission) from a variety of bodies, which may include local governments, tribal authorities, regulatory agencies and boards, and federal bodies. Higher volumes of applications associated with a faster pace of development may place strain on these processes and could be a contributing factor to delays. Further, in some cases, local ordinances or opposition to project siting may further constrain development opportunities.
- **Operations & market integration:** as the resource mix shifts towards increasing levels of variable and energy-limited resources, grid operations are becoming significantly more complex. Utilities will need more advanced forecasting capabilities (e.g., load, weather, and renewable generation), enhanced real-time visibility, and more sophisticated dispatch strategies to maintain reliability. Effectively integrating storage resources will be especially critical, requiring optimized charging and discharging strategies to capture their full reliability value.
- **Fuel supply:** with the expectation that the region's reliance on natural gas as a capacity resource will increase over the next decade, the region's utilities must also right-size their fuel transportation rights. Several utilities within the region are currently relying upon timely completion of a new interstate pipeline – a project subject to permitting and approval processes in multiple jurisdictions – by the early 2030s to allow for incremental delivery capability to new natural gas power plants.

Delays or unexpected obstacles caused by any one of these factors – or further increases in regional demand not anticipated at the time of this study – could jeopardize utilities' ability to add resources to the system at the pace needed to meet regional growth projections reliably. To mitigate these risks and support successful implementation, utilities and regional stakeholders can focus on several near-term actions:

- **Proactively manage large customer load risks:** strengthen interconnection and service agreements (e.g., financial commitments, phased delivery structures); design rates or tariffs that better align large customer development with system planning needs
- **Accelerate procurement timelines and optionality:** initiate procurements earlier; maintain diversified pipelines of projects to limit systemic risks; incorporate flexibility to account for delays or cancellations; leverage cost-effective demand-side programs to reduce scale of bulk system needs
- **Coordinate transmission and resource planning:** pursue parallel development of generation and transmission through Integrated System Planning; prioritize upgrades that enable access to diverse resource options; repurpose existing infrastructure made available with resource retirements
- **Streamline permitting and stakeholder engagement:** engage early with permitting agencies and local communities to identify and address potential barriers before they delay projects; explore potential to streamline local permitting with model ordinances; repurpose existing brownfield power plant sites
- **Enhance operational capabilities:** invest in advanced forecasting, grid visibility tools, and optimized dispatch strategies, particularly for energy storage and hybrid resources; coordinate with market operators to ensure market rules enable maximum storage value
- **Strengthen fuel and market coordination:** secure fuel transportation capacity needed to support resource plans; identify short-term risk mitigation strategies to ensure adequacy in the event of delay

While these actions cannot fully eliminate implementation risk, sustained focus in these areas will improve the likelihood that planned resources are delivered on time and that regional reliability is maintained under increasingly uncertain conditions.